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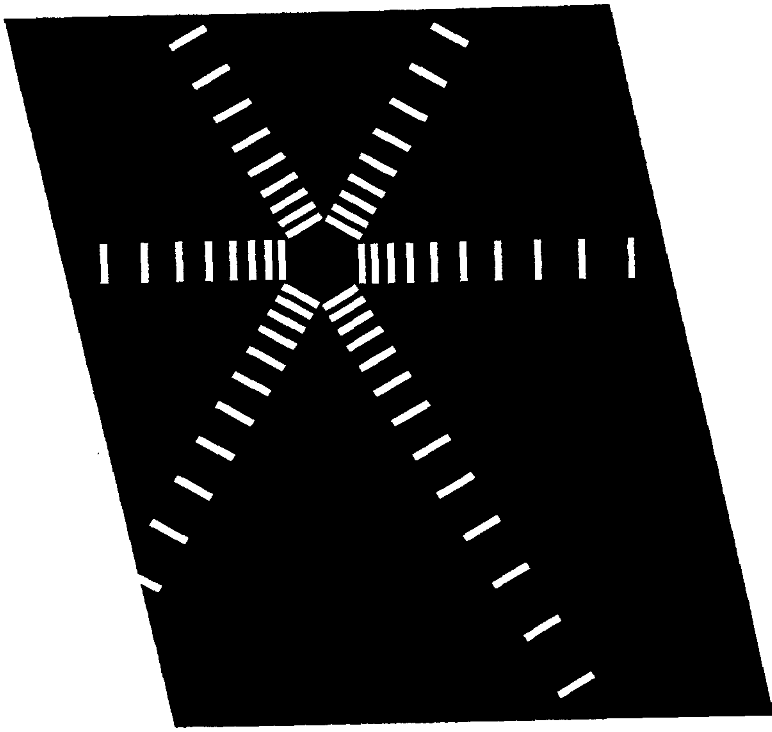

U.S. Energy Flow–1996

H. Miller
A. Pasternak

December 1998

Lawrence Livermore
National Laboratory

Work performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract W-7405-Eng-48.

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[illegible]

Abstract

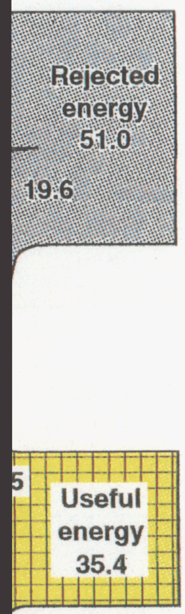
Energy consumption increased more rapidly in 1996 than in recent years, up 3.2% (91 to 94 quadrillion [10^{15}] Btu), outpacing economic growth of 2.4%. Unusually severe weather in 1996 resulted in the residential and commercial sector consuming 7.8% more natural gas and 3.5% more electricity than in 1995. Natural gas prices increased sharply resulting in electric utilities reducing their gas consumption by 15%, substituting coal as a source of energy production. This resulted in a sharp increase in total carbon emissions as well as emissions per kilowatt-hour for the electric utility sector. Associated rapid increases in carbon emissions resulted from both direct (burning of natural gas and heating oil) and indirect (from electricity) emissions from the residential and commercial sector. Consumption by the industrial and transportation sectors grew at a "more normal" rate, both at 2.4%, as did their associated emissions (2.6% and 2.3% respectively). Growth in nuclear power generation leveled off, and 1996 hydroelectric generation was the second highest on record.

Introduction

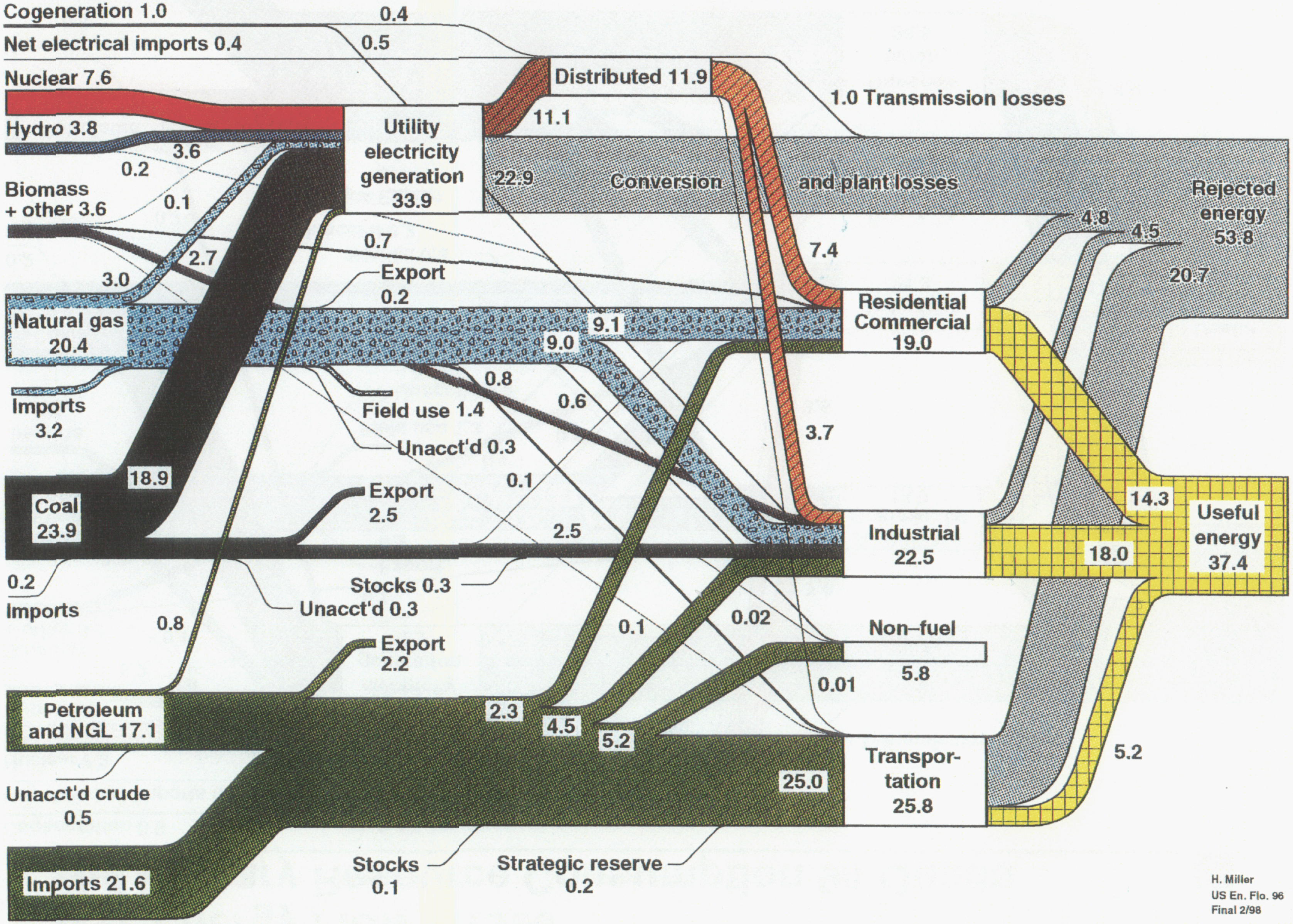
United States energy flow charts tracing primary resource supply and end use consumption have been prepared by members of the Energy program and planning groups at Lawrence Livermore National Laboratory since 1972. These charts are convenient graphical devices to show relative size of energy sources and end uses because all fuels are compared on the basis of a common energy unit. The amount of detail on a flow chart can vary substantially, and there is some point where complexity begins to interfere with the main objective of the presentation. The charts in this report have been drawn for clarity and to be consistent with the style used previously.

Energy Flow Charts

Figure 1 is the energy flow chart for calendar year 1996, in quadrillion (10^{15}) Btu; Figure 2 is the same flow chart in exajoules (10^{18} joules). The 1996 chart is based on final data published by the Energy Information Administration of the U.S. Department of Energy (AER 1997; MER 12/97; REA 1997). Conventions and conversion factors used in the construction of the charts are given in Appendix A. These data in many instances are revisions of preliminary data previously reported in this series.


Rejected
energy
51.0
19.6
5
Useful
energy
35.4

U.S. Energy Flow – 1996
Net Primary Resource Consumption 99 Exajoules



Other: geothermal, solar, wind, waste

Comparison of Energy Production and Use with 1995 and Earlier Years

Economic Indicators

Two traditional indicators of the energy intensity of the economy are (1) the relationship between energy consumption and real gross domestic product (GDP), and (2) the per-capita consumption of energy. In 1970, 20,000 Btu of energy were consumed for each chained (1992) dollar of GDP. Higher energy prices of the early 1970s encouraged increases in energy efficiency and a major restructuring of the energy-intensive activities of the manufacturing sector. By 1985, the energy intensity of the economy as a whole dropped to below 14,000 Btu per chained (1992) dollar and has remained there through 1996 (AER 1996, 1). In 1996, energy consumption per dollar of GDP was 13,000 Btu per 1992 chained dollar (MER 5/98, T 1.9).

The U.S. economy continued to improve in 1996 with an increase in the GDP of 2.4% in 1996 compared to 2.1% in 1995 (Table 1). Over the last few decades, the U.S. has experienced a slowing in growth for the economy primarily due to a slowing down in the rate of growth of population and the labor force for the U.S. In the 60's growth was around 4.4%, in the 70's, 3.2%, in the 80's, 2.8%, an in the 90's around 2.1%. Against this data, the 2.4% growth in 1996 might be considered low from a long-term historical view, but relatively strong given the slowdown in growth in the 90's. The DOE/EIA's long-term projected growth rate for the economy between 1997 and 2020 is 2.1% per year. However due to a slowdown in labor force growth, economic growth is expected to decline each year throughout the forecast period, and by the end point in 2020, it may

Table 1. Gross domestic product (GDP) by major type of product (In billions of dollars)				
	1995		**1996**	
	Chained $	**Current $**	**Chained $**	**Current $**
Gross domestic product	6,742.2	7,253.8	6,906.8	7,576.1
Goods	2,588.5	2,699.2	2,662.0	2,799.8
Services	3,583.9	3,926.9	3,649.2	4,105.2
Structures	571.8	627.6	598.3	671.1

Source: *Statistical Abstract of the United States 1997: The National Data Book,* U.S. Department of Commerce, 117th ed. (Oct. 1997) T 694.

[a]"Chained dollars" is a measure of output and prices calculated as the average of changes based on weights for the current and preceding years. Components of real output are weighted by price, and components of prices are weighted by output. These annual changes are "chained" (multiplied) together to form a time series that allows for the effects of changes in relative prices and changes in the composition of output over time.

End-use energy consumption per capita trended downward from the peak of 1973 (285 million Btu) to a low of 226 million Btu in 1983. Low petroleum prices of the 1990s has encouraged energy use, resulting in an increase in end-use energy consumption to 269 million Btu per capita in 1996, a 2.3% increase over 1995 and a 5.1% increase since 1990 (AER 1996, 1). The growth in end-use energy consumption continues to exceed the growth in U.S. population (Fig. 3). Since 1992, annual growth in end-use energy consumption has been approximately 2%, and the growth in U.S. population has been on the order of 1%. In 1996, however, end-use energy consumption increased 3.1% above 1995 rates, with the population increasing only 0.9% (AER 1996, T 1.5).

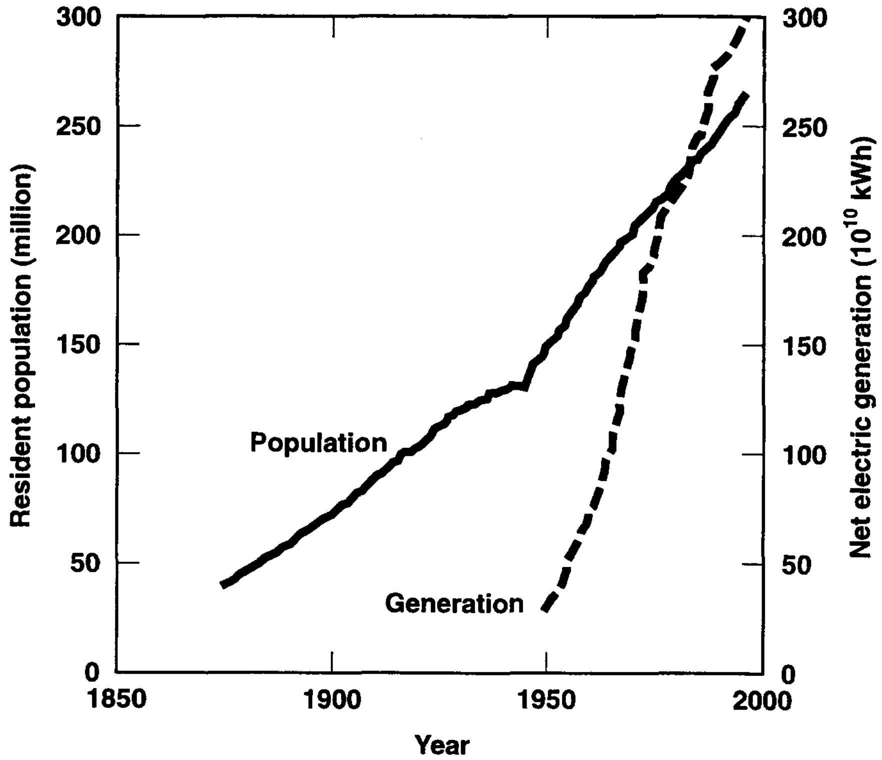


Figure 3. Growth of U.S. population and net utility electrical generation.
Source: *Historical Statistics of the United States—Colonial Times to Present*, U.S. Department of Commerce, Washington, DC (1975) Series A 6-8; *Annual Energy Review—1996*, DOE/EIA-0384(96), U.S. Department of Energy, Washington DC (July 1997) T 8.3; *Statistical Abstract of the United States—1996*, U.S. Department of Commerce, Washington, DC (1996) Table 2; *Monthly Energy Review*, DOE/EIA-0035(97/07), U.S. Department of Energy, Washington, DC (July 1997) T 7.1.

Production and Consumption

Historically, three fossil fuels (coal, crude oil, and natural gas) have been the dominant sources of energy production in the U.S. (Table 2). These fuels produced 58.2 quads or 80% of the total energy produced in 1996 (72.8 quads). The total domestic production of crude oil and natural gas liquids (NGL) in 1996 decreased by 0.5% whereas consumption increased by 4.9%. Demand for liquid petroleum continues to be dominated by the transportation sector but increased demand for petroleum exists for all end-use sectors. Domestic production of coal increased by 3% and overall consumption increased by 2%. Coal continues to contribute the largest share of electric energy produced in the U.S. (Fig. 4). Use of coal by all end-use sectors other than electric utilities however has been generally declining for several decades (Fig. 5–7). Production of natural gas increased by only 1.1% while consumption increased by 1.8%. (Table 2).

Table 2. Comparison of annual energy production and consumption in the United States.

	Quads (10^{15} Btu)							
	1989	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**
Natural gas production	17.85	18.36	18.23	18.38	18.58	19.27	19.10	19.30
Net imports	1.39	1.55	1.80	2.16	2.40	2.68	2.90	3.00
Natural gas consumption	19.38	19.30	19.61	20.13	20.83	21.29	22.16	22.56
Crude oil and NGL								
Domestic production	18.28	17.74	18.01	17.58	16.90	16.49	16.33	16.25
Imports (incl. SPR)	17.17	17.12	16.34	16.96	18.51	19.25	18.86	20.62
Exports (crude oil)	1.84	1.82	2.13	2.01	2.12	1.99	1.99	2.06
SPR (storage reserve)[a]	0.12	0.04	-0.10	0.03	0.07	0.03	0.00	0.15
Net consumption[b]	34.21	33.55	32.85	33.53	33.84	34.73	34.66	35.86
Coal production (incl. exports)	21.35	22.46	21.59	21.59	20.22	22.07	21.98	22.64
Coal consumption	18.92	19.10	18.77	19.21	19.83	20.02	20.09	20.49
Total fossil fuel consumption	**72.55**	**71.96**	**71.23**	**72.89**	**74.51**	**76.06**	**76.94**	**79.92**
Renewable consumption[c]	3.10	6.17	6.27	6.11	6.40	6.30	6.83	7.39
Electricity								
[Utility consumption for electricity generation]								
Fossil fuels (gross)	20.54	20.32	20.06	19.99	20.58	20.92	20.92	21.44
Natural gas	2.87	2.88	2.86	2.83	2.74	3.05	3.28	2.80
Coal	15.99	16.19	16.03	16.21	16.79	16.90	16.99	17.93
Oil	1.69	1.25	1.18	0.95	1.05	0.97	0.66	0.73
Renewables[d]			3.30	2.97	3.22	3.01	3.45	3.88
Conventional hydro			2.90	2.51	2.77	2.54	3.05	3.42
Biofuels and other[e]			0.19	0.19	0.18	0.17	0.12	0.13
Net electricity imports			0.21	0.26	0.27	0.31	0.28	0.33
Nuclear (gross)	5.68	6.16	6.58	6.61	6.52	6.84	7.18	7.17
Transmitted elect. (total)	**9.61**	**9.60**	**9.87**	**10.13**	**10.53**	**10.90**	**11.00**	**11.25**
End-use consumption								
Residential & commercial[f]	16.26	16.21	16.66	16.79	17.39	17.41	17.87	18.02
Industrial[g]	22.27	25.02	24.74	25.82	26.16	26.91	27.30	28.20
Transportation	22.56	22.54	22.12	22.46	22.88	23.57	23.96	24.52
Total consumption[h] (DOE-EIA/LLNL)	**81**	**84**	**84**	**86**	**87**	**89**	**91**	**94**

Source: *Annual Energy Review*, U.S. Department of Energy, DOE/EIA-0384(96) (July 1997) Table 2.1; *Renewable Energy Annual*, DOE/EIA-0603(96 and 97) (Mar. 1997 and Feb. 1998) Tables 1–4; *Annual Energy Outlook*, DOE/EIA-0383(97) (Dec. 1996) Table B.8.

[a]The strategic petroleum reserve storage began in October 1977. A value of 0.0 = less than +500 barrels/day and greater than -500 barrels/day.

[b]Excludes exports but takes into account refinery gains, SPR additions, and other stock changes as well as unaccounted crude oil. Note that this total is not the sum of the entries above.

[c]Includes conventional hydroelectric; net imports of hydroelectric from Canada and geothermal from Mexico; biomass, solar (thermal and voltaic), and wind. This energy is used by all the end-use sectors and by the industrial and electric utility sectors for electricity generation. There is a discontinuity in this time series between 1889 and 1990 because of expanded coverage of nonutility use of renewable energy beginning in 1990.

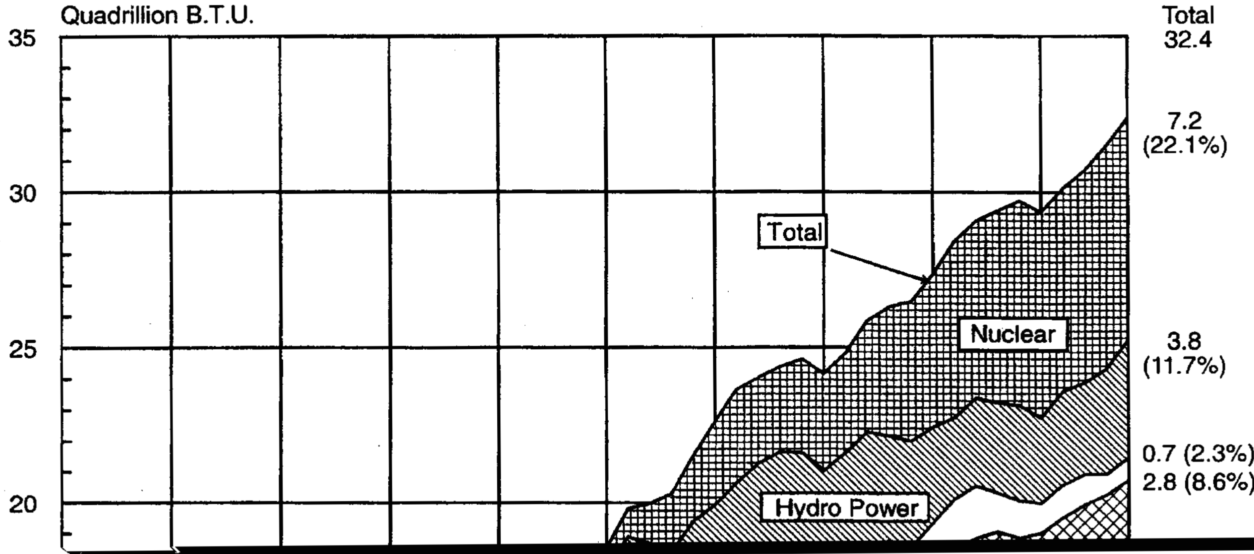
[d]Includes generation of electricity by cogenerators, independent power producers, and small power producers. Includes net imports.

[e]Biofuels include wood, woodwaste, peat, woodsludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils and/or other waste. Also included are geothermal, solar, and wind. Solar and wind contribute less than 0.5 trillion BTU (1991–1995).

[f]Excludes electrical losses.

[g]Includes field use of natural gas and non-fuel category and excludes electrical losses. Value for industrial consumption shown on Fig. 1 and 2 excludes field use of natural gas and non-fuel use of petroleum as well as electrical losses.

[h]Note that this is not the sum of the entries above. In addition, numbers reported previously in this series prior to 1995 underestimated energy produced from biofuels thus affecting total consumption quantities.



Quadrillion B.T.U.
35
30
25
20
Total
32.4
7.2
(22.1%)
3.8
(11.7%)
0.7 (2.3%)
2.8 (8.6%)
Total
Nuclear
Hydro Power

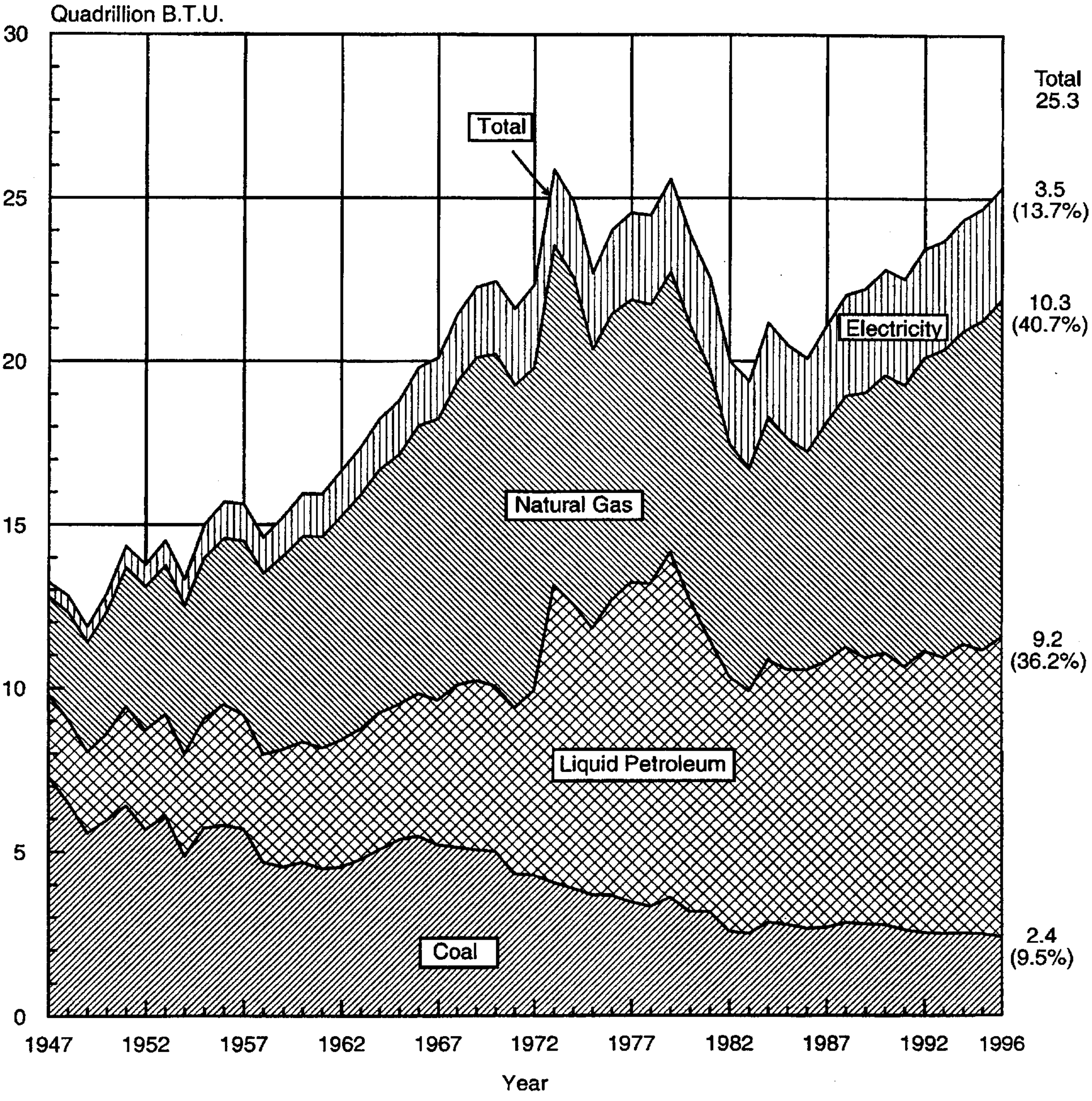


Figure 5. United States end-use energy demand in the industrial sector. Source: *Twentieth Century Petroleum Statistics 1997*, 53rd ed., DeGrolyer and MacNaughton, Dallas, Texas (Nov. 1997), Chart 109.

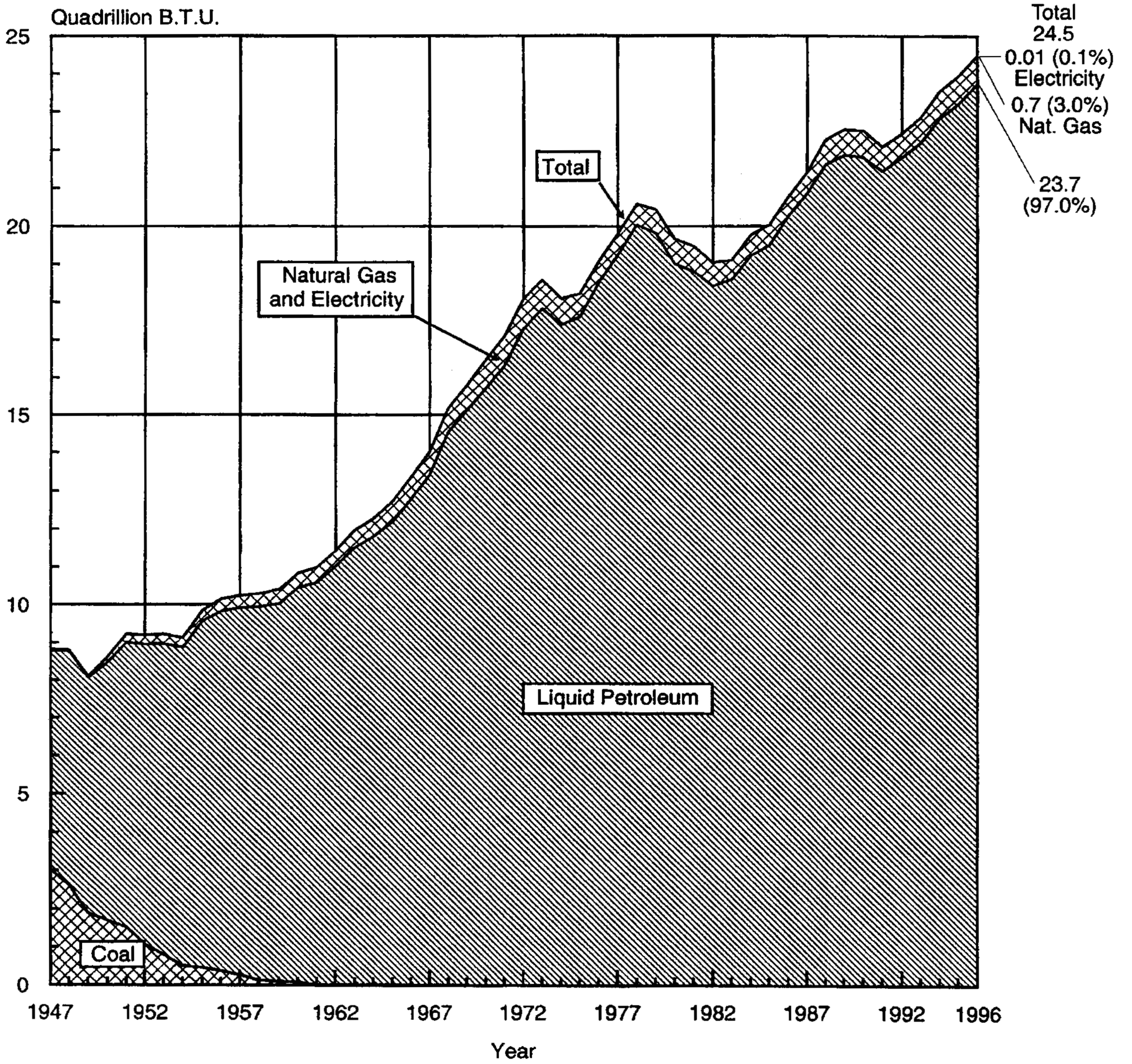


Figure 6. United States end-use energy demand in the transportation sector. Source: *Twentieth Century Petroleum Statistics 1997*, 53rd ed., DeGrolyer and MacNaughton, Dallas, Texas (Nov. 1997), Chart 111.

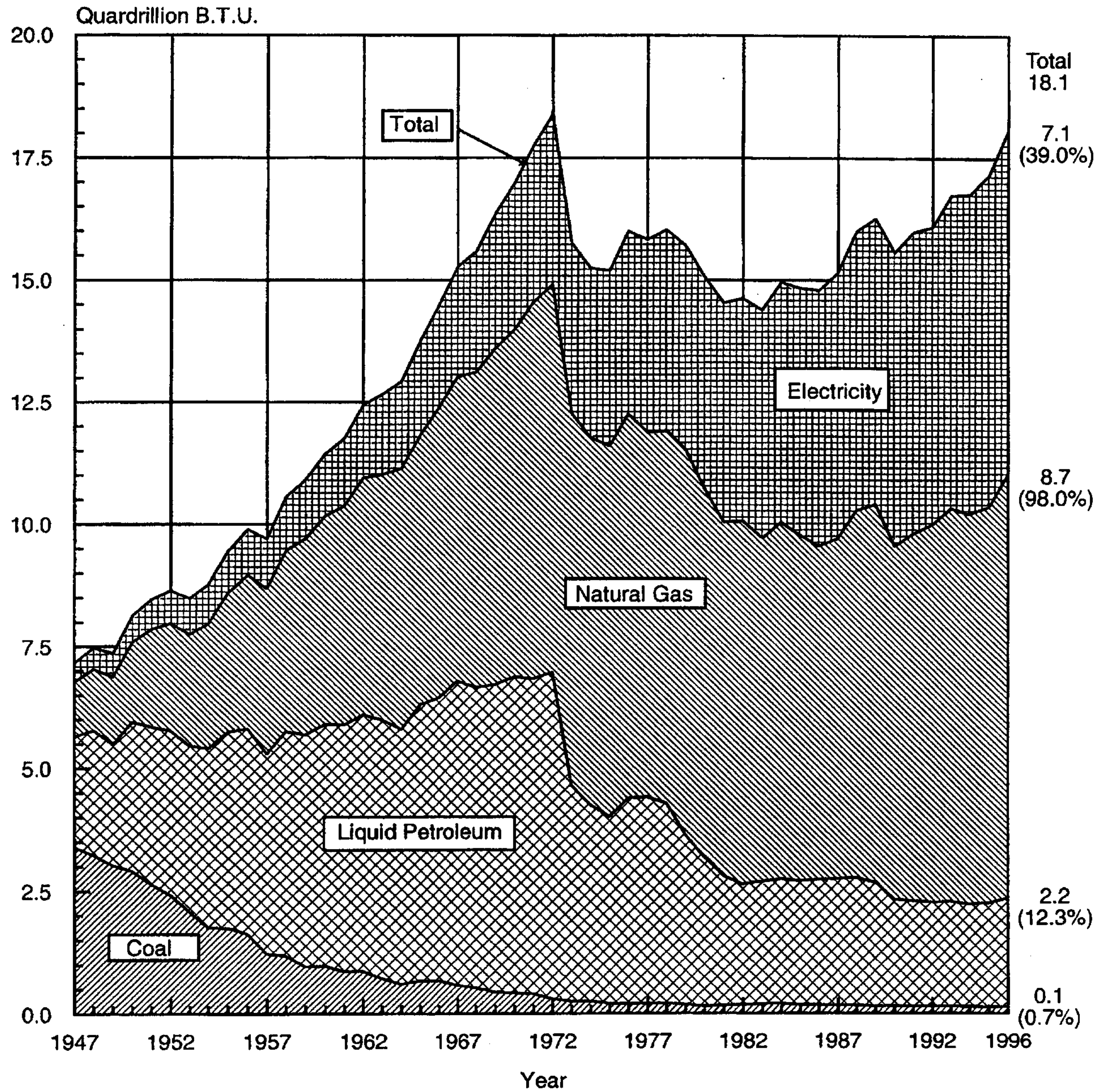


Figure 7. United States end-use energy demand in the residential and commercial sectors. Source: *Twentieth Century Petroleum Statistics 1197, 53rd DeGrolyer and MacNaughton, Dallas, Texas (Nov. 1997), Chart 110.*

Hydroelectric energy continues to be the predominant renewable source of electricity. Approximately 3 quads of electric energy has been supplied annually from the 1970s through 1995 (with the exception of drought years, 1977 and 1988). In 1996, hydroelectric power reached a record high of 3.5 quads (AER 1996 T. 8.3 and 10.1).

Other renewables, (e.g., biofuels, geothermal, solar, and wind energy) are generally increasing in their contribution to the domestic energy supply. Biofuels contributed 2.6 quads in 1991, and in 1996 reached 3.0 quads, a 15% increase. The contribution of other renewables has been steady from 1991 through 1996, with solar and wind energy together contributing 0.1 quad and geothermal contributing 0.4 quad.

For the sixth consecutive year, U.S. energy consumption in 1996 registered an increase, up approximately 3% from 1995 (Table 2). After the oil shock of 1973, energy consumption vacillated because of large changes in oil prices, changes in the rate of domestic economic growth, and concerns over the impact of energy use on the environment. Since 1973, energy consumption reached a low point in 1983 (70.5 quads) following a period of very high oil prices. Energy consumption in 1996 reached an all-time high of 93.8 quads (98.9 exajoules) (AER 1996, T 1.3)

Energy consumption in each of the three principal end-use sectors reached its highest recorded level in 1996 (Table 2; Fig. 5–7). Although economic growth in the 1990s has been slow, industrial energy consumption has trended upward, reaching 21.3 quads in 1996 excluding non-fuel uses, representing a 23.3% increase over 1990 levels and a 3.2% increase over 1995 levels. Natural gas and petroleum fuels dominated industrial consumption in 1996 at 8.5 and 4.3 quads respectively. (Note: values for industrial consumption shown in Table 2 exclude electrical losses and include field use of natural gas and non-fuel use of petroleum, whereas the U.S. Energy Flow diagrams shown as Fig. 1 and 2, show field use of natural gas and non-fuel use of petroleum separately and are not included in the value for industrial energy consumption.)

The residential and commercial sectors together consumed 18.0% quads in 1996 (excluding electrical losses), representing a 11.2% increase since 1990 and a 0.8% increase above 1995 consumption levels. This was primarily due to increased consumption of natural gas and electricity, at 8.7 and 7.0 quads respectively (AER 1996, T 2.1). The residential sector has increased its use of natural gas by 19.4% since 1990 and 8.1% since 1995 (MER 12/97, T 4.4). The use of electricity by this sector has increased 16.7% since 1990 and 3.5% since 1995. Similarly, the commercial sector has increased its use of natural gas by 20.4% since 1990 and 4.2% since 1995 (MER 12/97, T 4.4 and 7.2). Electricity consumption by this sector has increased only 3.5% since 1990 and 3.4%

since 1995. The residential and commercial sector's increased consumption of natural gas and electricity is associated with decreased consumption of coal and petroleum.

The transportation sector's energy consumption reached 24.5 quads in 1996, a 10.6% increase since 1990 and a 2.3% increase over 1995 levels, primarily from the use of petroleum. This sector consumed approximately 0.1 quads of biofuels (ethanol blended into gasoline), and 0.7 quads (3 billion cu. ft.) of natural gas. Most of the natural gas used by this sector was consumed in the operation of pipelines (compressors), and a small amount is attributed to the use of natural gas as vehicle fuel. Electricity consumption by the transportation sector, at 0.01 quad, has not changed since 1990 (MER 12/97 T 2.5 and 4.4).

The amount of electricity transmitted by the utilities increased by 2.3% in 1996 compared to 1995. Total utilities consumption of fuels for electricity generation was 32.2 quads compared to 31.3 quads in 1995. Utilities increased consumption of coal by 5.5%, conventional hydroelectric by 12.3%, biofuels by 17.6%, and geothermal (including imports) by 5.1%, whereas consumption of natural gas decreased by 17.1% (REA 1997, vol. 1, T 3). Consumption of nuclear power, petroleum and solar energy for the generation of electricity remained essentially unchanged from 1995 (MER 12/97, T 2.6).

Supply and Demand of Fossil Fuels

Oil Supply

Domestic Production

Oil production in the United States decreased for the sixth year in a row. Crude oil production fell almost 1.5% in 1996 to 2,359 million barrels (of 42 U.S. gallons). Natural gas liquids (NGL) production, comprising 21% of the total petroleum produced in the U.S., increased 3.9% to 850 million barrels (MER 12/97, T 3.1a). Of the total U.S. production, 76% came from onshore wells and the rest from federal offshore wells (AER 1996, 133).

At the beginning of 1996, crude oil reserves were 22.35 billion barrels; NGL 7.40 billion barrels. By December 31, 1996, proved reserves of crude oil had decreased over the year by 334 million barrels, reaching 22.02 billion barrels; NGL proved reserves increased 424 million barrels to 7.82 billion barrels. Since 1986, U.S. crude oil proved reserves have been declining approximately 2% per year, an average annual rate of 607 million barrels. The 1996 decline is 55% of that average (U.S. Crude 1996, 3, 4, 19).

The largest decrease in crude oil reserves was in Alaska (306 million barrels); the largest increase occurred in the federal offshore areas in the Gulf of Mexico: 49 million barrels of crude were added (U.S. Crude 1996, 3, 4). Crude oil reserves have been sustained primarily by revisions and adjustments to defined reserves of older fields rather than by total discoveries. Of all crude oil reserves additions since 1977, 63% are attributed to revisions and adjustments and the balance of 37% to total discoveries. However, since 1977, U.S. operators have: (1) discovered an average of 792 million barrels/y of new reserves, (2) revised and adjusted then proved reserves upward by an average of 1,359 million bbl/y, and (3) reduced proved reserves by an average of 574 million bbl/y (U.S. Crude 1996, 8, 9).

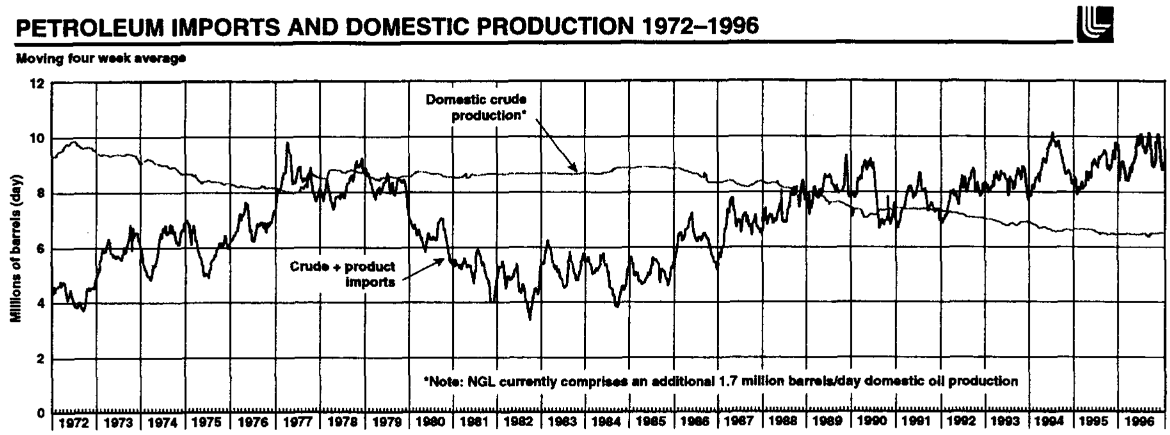
However, 1996 was a good year for crude oil discoveries. Four areas had total discoveries greater than 35 million barrels: Gulf of Mexico Federal Offshore (319 million barrels), Alaska (192 million barrels), Texas (163 million barrels), and Louisiana (89 million barrels) (U.S. Crude 1996, 22). The Gulf of Mexico is now considered the "hottest offshore basin in the world" as a result of new deepwater production (OGJ 5/13/96, 29–30). "Indicated additional reserves" of crude oil, i.e., crude volumes that may become economically recoverable from known reservoirs through the application of improved recovery techniques using current technology, were 2,876 million barrels in 1996, an 8% increase over 1995. Large "indicated additional reserves" have been identified at the Alaskan North Slope, California, Texas, and Louisiana. These reserves indicate that significant upward revisions to crude oil proved reserves will continue to occur in the future (U.S. Crude 1996, x).

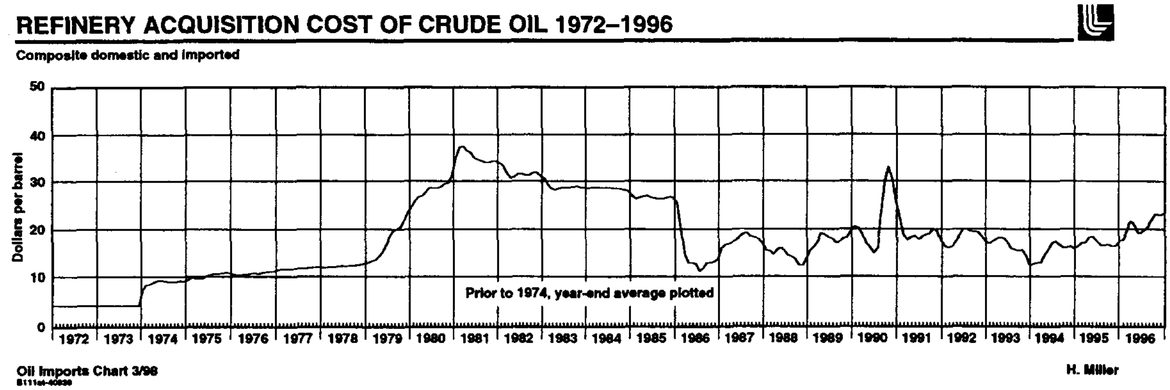
In 1996, the Clinton Administration proposed to sell oil from the Strategic Petroleum Reserve (SPR) to help balance the federal budget. Although this decision was considered "regrettable" by DOE, the Administration sold 5.1 million barrels of "sour crude" at an average price of $18.92/bbl to pay the costs of closing the Weeks Island, Louisiana site, raising $96.4 million from the sale. The proposal included selling 15–17 million barrels of oil from the SPR by October 1, 1996, to raise another $292 million. Funds were to be used to decommission Weeks Island and improve other SPR sites (OGJ 4/8/96, 4)

Deepwater production is the frontier in oil exploration. Advancing technology has been key to extending off-shore oil and gas exploration and development (E&D) into new frontiers, enabling production activities in ever-deeper water. Technologies include floating platforms and the use of subsea well completions. Fields in the deepwater (water depths of 200 meters or more) are producing crude oil at nearly twice the annual rate (97 million barrels) than they were in 1992 when production was 54 million barrels. This is a testament to the successful implementation of the new technologies. Tracts in water depths of 200 meters or more are also eligible for consideration under provisions of the Deepwater Royalty Relief Act signed by President Clinton in November 1995 (U.S. Crude 1996, 22, 24). These provisions reduce the tax-rate on extractions from deepwater. Enthusiasm has been greatest in the U.S. Gulf of Mexico where the deepwater royalty relief has helped to set lease sale records and fuel development activity (OGJ 1/6/97, 30).

Domestic crude oil prices increased again for the fifth year in a row, with the annual average first purchase price reaching $18.46/ bbl, up 26% from 1995, and the highest average price since 1990 (MER 12/97, T. 9.1)."Drastically low" U.S. oil stocks were a key factor in oil price strength in 1996; however, increased demands and unusually cold weather trends were also significant factors affecting product prices in the United States. A deep freeze and storms in the early part of 1996 contributed to keeping oil and gas prices strong (OGJ 1/8/96, 2; OGJ 6/10/96, 2). Prices started at $15.43/bbl in January, reached $19.58/bbl in April, and peaked at $21.32/bbl in December. Figure 8 shows the refinery acquisition cost of crude oil, a composite of both domestic and imported oil. Refinery acquisition average cost in 1996 for domestic crude was $20.77 and for imported crude was $20.64 (MER 12/97, T. 9.1).

Figure 8: Petroleum imports and domestic production and refiner acquisition cost of crude oil.





A volatile U.S. oil market in 1996 resulted from low world oil stocks, high world oil demand, and early cold weather. A jittery spot market, resulting from the suspension of United Nations-sanctioned sale of Iraqi oil and associated political tension in September, drove world and domestic oil prices to about $23.00/bbl and in the fourth quarter of 1996. The $3.40/bbl crude oil increase in 1996 was passed through to all petroleum products. (Short Term Energy Outlook, 1/97, 14–16) Weather conditions, described as unusually cold through the 1995–1996 and 1996–1997 winter seasons also contributed to keeping oil and gas prices strong.

Higher oil and gas prices were better than better than hoped for by some segments of the industry (oil and gas producers); however, for refiners and marketers and for energy customers the trend was not good. Consumers called for government intervention twice in 1996 when prices increased because of higher demand and new inventory strategies. However, in the end, the government kept its hands off the market. To cope with the high oil prices that put further pressure on already-weak U.S. refinery operating margins, refiners engaged in business consolidations and joint ventures to reduce costs and increase market shares. Oil service and supply companies formed alliances to improve their ability to provide more technology and service (OGJ 1/6/97, 30).

The unexpected price strength seen in 1996, the slimming of corporate structures, and new technology provided more funding for drilling and more exploration and development (E&D) spending. Whether in the form of joint ventures, alliances, mergers, acquisitions, or sales, the redistribution of assets and resources in 1996 spanned the petroleum industry from exploration through refining and marketing, and these strategies began integrating the petroleum and electric power industries on a large scale (OGJ 1/6/97, 30).

Controversy surrounded the value of the reformulated gasoline program in 1996, although it was touted by some in the (EPA) as one of the most significant steps under the Clean Air Act (CAA) to protect public health (by reducing urban smog) (OGJ 3/25/96, 19). The reformulated gasoline program encourages the use of oxygenate additives in gasoline, more specifically ethanol, up to 10% by volume, but has no specific mandates for percentages. California Air Resources Board (CARB) required California refineries to produce cleaner burning gasoline by March 1, 1996. Opponents of the program claim that ethanol does not improve the smog-fighting qualities of reformulated gasoline and believe that the marginal advantages in ozone reduction are offset by the increased volatility of the reformulated fuel. Moreover, opponents believe that since ethanol costs twice as much to produce as gasoline, reduces fuel mileage, and hampers engine performance if improperly blended, only the generous tax subsidy gives ethanol a market as a fuel additive (OGJ 3/25/96, 19).

The CARB defended the reformulated gasoline program in the face of concerns over rising gasoline prices in 1996. CARB Chairman declared that Californians paid an extra 5–8 cents/gal for cleaner, healthier air through the use of a "cleaner burning gasoline." CARB stated that the program is credited with the removal of 300 tons/day of toxins and other pollutants, reducing smog-forming emissions from motor vehicles by 15% and cutting the cancer risk from exposure to gasoline toxins by 30–40%. Major oil company executives testified at a California Energy Commission hearing on rising gasoline prices that sharp rises in crude oil prices were mostly responsible, not the reformulated gasoline program. Spokesmen from the oil industry pointed out that crude oil prices had risen 50%, or 20 cents/gal of gasoline (almost 40 cents/gal in California) because: (1) Iraqi crude oil did not appear on the market in the spring as anticipated; (2) demand for heating oil was high due to an unusually cold winter in much of the U.S.; and (3) of the combined effect of increasing demand for gasoline in the spring as well as operating problems as several California (OGJ 5/6/96, 42). Sharp increases of 17.5 cents/gal in diesel prices between February and May of 1996 also caused public concern; prices spiked 5.6 cents/gal in one week (April 15), the largest increase since the Persian Gulf war of 1991. President Clinton ordered the DOE to determine why gasoline and diesel prices had increased; the DOE/EIA confirmed the combined effects of the points cited by oil industry analysts and officials as contributing to the price volatility and uncertainty (OGJ 5/6/96, 42). DOE also expressed concern over the industry's practice of holding lower inventories (OGJ 6/24/96, 30).

Although the EPA has allowed U.S. oil refineries to use individual quality standards for gasoline under the reformulated gasoline program, they have required foreign refiners to meet statutory criteria. This caused a World Trade Organization (WTO) panel to rule that the U.S. regulation of imported oil constituted unfair trade practice. Although the WTO acknowledged the difficulty of administering EPA regulations outside the U.S., it nevertheless ruled that foreign refiners must be given the regulatory option offered to domestic refiners. Domestic refiners believed that the choice gave foreign refiners an unfair advantage. The EPA's goal was to ensure that environmental gains from the reformulated gasoline program were not offset by imported conventional fuel. Although there is merit to the program, there is concern from an energy security perspective that, as the U.S. toughens its product quality standards, fewer suppliers may be available to fill an ever-increasing need for imports of petroleum products (OGJ 7/8/96, 21).

Oil Imports

The U.S. remains heavily dependent on imported oil and gas to satisfy demand. In 1996, U.S. dependence on petroleum imports reached a 19-year high of 46% of its energy consumption; a 2% increase above 1995 levels (U.S. Crude 1996, 17). At 7.5 million barrels per day (b/d), crude oil imports in 1996 increased 3.9% since 1995, while petroleum product imports at 2.0 million b/d increased 22.8% (MER 12/97, T 3.1B). Strategic petroleum reserves were 566 million barrels at the end of 1996, increasing 4 million barrels above the ending 1995 levels.

The primary foreign suppliers of petroleum to the United States in 1996 (Fig. 9) were Venezuela (1.7 million b/d), Saudi Arabia (1.3 million b/d) and Nigeria (0.6 b/d) of the Organization of Petroleum Exporting Countries (OPEC); Canada (1.4 million b/d) and Mexico (1.2 million b/d) of the non-OPEC nations. These five countries collectively supplied 60.5% of total U.S. imports of petroleum (MER 12/97, T 3.3b-3.3h).

The American Petroleum Institute asserts that oil imports are not the major factor in U.S. negative trade balance (OGJ 1/1/96, 3). Crude oil imports in 1996 cost $56.5 billion, or 6% of the $949.9 billion spent for all imported goods and services. This can be compared to 1980, when crude oil imports cost $65.1 billion, or 19.4% of the $336.1 billion spent for all imported goods and services (MER 12/97, T 3.1b, and T 9.1; Stat. Abs. 1997, T1307; Stat. Abs. 1980, T.1522).

In June 1996, the Clinton administration decided to allow U.S. companies to import Iraqi crude and to sell food and medicine to Baghdad under the U.N. accord. However, tensions flared throughout the year between Iraq and the United States, delaying the deal indefinitely. This caused international crude prices to increase substantially (Pet. Mktg. 1996, xxxiii). The State Department considered barring U.S. firms from buying Iraqi oil but could not justify the action. The DOE argued that a ban would not help U.S. foreign policy goals but would put U.S. oil companies at a disadvantage (OGJ 6/17/96, 2).

The Government Accounting Office (GAO) stated in a major study challenging long-standing U.S. energy policy that the real driver behind U.S. energy vulnerability was the country's overall consumption of oil, not imports. Although reducing oil imports would benefit U.S. oil producers and their shareholders, the GAO showed that reducing imports would cost the U.S. billions of dollars in lost gross domestic product and provide little protection, if any, against oil shocks. The DOE's 1995 National Energy Policy Plan cited many ways to reduce U.S. dependence on foreign oil, calling for increasing energy efficiency and alternative energy supplies; increasing domestic production of oil and other fossil fuels; and using the SPR to provide protection from oil shocks. Although the GAO acknowledged that DOE's plan "might make the economy less vulnerable...the EIA's projections indicate that increases in the demand for oil may offset many of the gains. Forecasts that assume a continuation of DOE's policies and programs show improvement by 2015 in only one measure of vulnerability-the oil intensity of the U.S. economy." Use of the SPR in an oil crisis was the only tool the GAO saw as effective in the near term. The DOE was critical of the GAO's conclusions, noting that 14 independent energy experts endorsed the agency's energy plan; and although the GAO agreed that its independent experts "endorsed much of the plan,...the experts' view differed in important respects from DOE's, most notably that increasing domestic oil production would reduce the nation's energy vulnerability. Many also opposed subsidies for alternative energy sources." (Energy Daily, 12/16/96)

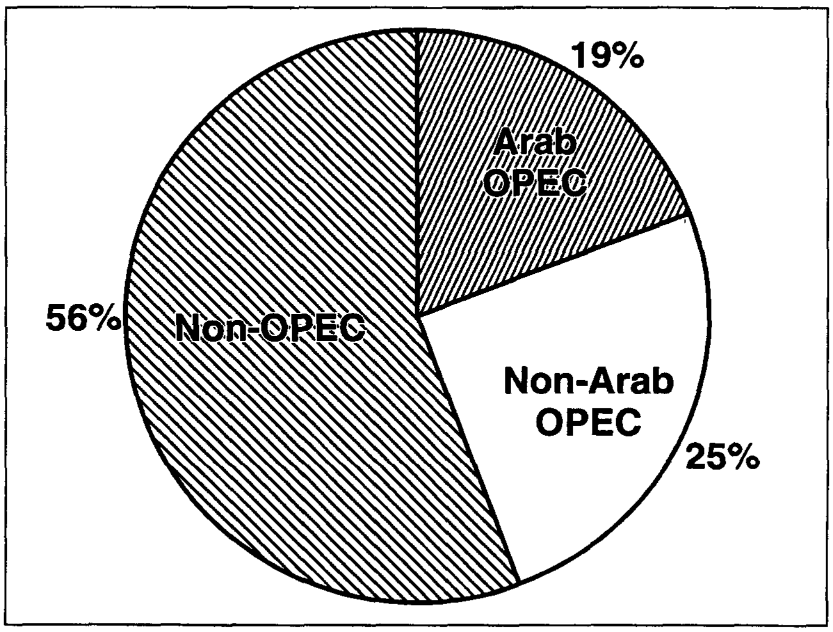


Figure 9. Source of U.S. petroleum imports in 1996.
Source: *Monthly Energy Review*, DOE/EIA-00035(97/12), U.S. Department of Energy, Washington, DC (Dec. 1997) Table 3.3a-h.

Oil Demand

Of the 93.8 quads of energy consumed in the U.S. in 1996, 38% was provided by crude oil and natural gas liquids (NGLs), equivalent to 18.3 million barrels of oil and NGLs per day. Consumption of petroleum products by sector were as follows in 1996: residential commercial, 2.2 quads; industrial, 9.2 quads; and transportation, 23.7 quads

(MER 12/97, T 2.3-2.5). Petroleum demand growth for 1996 exceeded projections of 2.8% over 1995 levels, reaching 3.5%, equivalent to an estimated increase of 625,000 b/d (MER 12/97, T 1.4; Energy Outlook 1997, 12,13). Distillate sales were up 3.7%, driven upward by an expanding economy and by substantial growth in freight traffic. Residual fuel oil sales increased for the first time since 1988, up 7.7% above 1995 levels. This increase was a consequence of extremely cold weather during the beginning of 1996 as well as competitive prices toward the end of 1996 (Fuel Oil 1996, 3). Disposition of finished motor gasoline at 7,891 thousand b/d (product supplied) decreased 1.3% from 1995 as demand decreased due to weather-related poor driving conditions and higher average retail prices (MER 12/97, T 3.4). Jet fuel demand increase was strong at 4.9%, and residual fuel oil demand remained flat with 1995 levels (Energy Outlook 1997, 12,13).

The DOE's Energy Information Agency (DOE/EIA) has identified the following oil demand and supply sensitivities:

- "A 1% increase in the real GDP raises the petroleum demand by about 120,000 barrels per day;
- A $1-per-barrel increase in crude oil prices, reduces the demand by about 69,000 barrels per day (assuming no price response from nonpetroleum energy sources);
- A $1-per-barrel increase in crude oil prices boosts domestic oil supply (crude oil and natural gas liquids production) by about 95,000 barrels per day.
- A 1% increase in cooling degree-days increases petroleum demand by about 8,000 barrels per day" (Energy Outlook 1997, 17).

Distillate sales went up in every category except commercial and military use. Factors critically affecting distillate sales in 1996 were the economy, weather, and crude oil prices. A vital economy, indicated by a 4.4% increase (in current dollars) in the GDP, had the most influence on distillate sales in the transportation sector, pushing distillate sales up 5% in this sector. At 27.0 billion gallons, on-highway diesel sales reached 82% of the distillate sales in the transportation sector; sales went up primarily due to the increased demand for goods and services (Fuel Oil 1996, 3).

Residential consumption of distillates for home heating remained relatively unchanged from 1995, despite the colder heating season, up only 0.7% in 1996. Only 12.9% of all distillate sales were for residential use; 82.8% of those sales were in PAD District I. The principal reason for sales remaining steady in 1996 was a result of an increase in natural gas consumption stimulated by competitive pricing. Natural gas prices increased only 0.8% while residual heating oil prices increased 10.7% (Fuel Oil 1996, 3,4).

Commercial use of distillate fuels decreased 0.7% (27 million gallons), primarily due to decreased on-highway use of diesel by governments. Vessel bunkering dominated the residual fuel market, securing 43.0% of the market, even though vessel bunkering sales were down 3.0%. This decrease in sales was in part due to the unusually high demand for residual fuel by the electric utilities (Fuel Oil 1996, 4,5).

Industrial use of distillate increased 2.2% (50 million gallons) in 1996, because of a growing economy and increased manufacturing production (Fuel Oil 1996, 3).

Residual fuel oil sales in the U.S. increased for the first time since 1988, a 7.7% increase driven by a 31.9% increase in electric utility sales. Electric utility sales accounted for 32.4% of all residual fuel sales, rising to 4.3 billion gallons in 1996. This 5.9% upward shift in sales was principally due to three factors. First, the harsh winter in the Northeast and Mississippi regions in the first quarter of 1996 raised electric utility demand for residual fuel oil; gas pipes froze in Mississippi, causing utilities to increase their use of residual fuel oil. Second, Northeast Nuclear Energy was forced to shut down four of its plants because of safety violations causing a substantial drop in nuclear power; the three Millstone plants were shut down in March 1996 and the Connecticut Yankee plant was shut down in July. Third, as a result of a 68% increase in natural gas prices in November and December 1996, and the competitive pricing of residual fuel oil, electric utilities were encouraged to rely more upon residual fuel oil (Fuel Oil 1996, 5).

Transportation Demand

In the transportation sector, consumption of petroleum products continued to rise in 1996. The 23.7 quads of petroleum products consumed by this sector in 1996 represents a 2.4% increase over 1995 levels and an 8.9% increase over 1990 levels. Of the total energy consumed by this sector (i.e., 24.5 quads) 96.7% was in the form of petroleum products; 0.7 quads or 3% as natural gas; and only 0.01 quad or 0.06% as electricity (MER 12/97, T 2.5). Natural gas consumption increased only 0.012 quad above 1995 levels, and electricity consumption was up only 0.001 quad from 1995 levels.

Alternative Fuel Program

Since the Energy Policy Act (EPACT) was passed in 1992 in response to energy security issues raised by the 1991 Persian Gulf conflict, the focus of the Act has been on energy efficiency and improving domestic energy supplies (Trans. Fuels 1996, 7). In accordance with the EPACT, the DOE issued a rule in 1996 requiring states and certain companies to add alternative fuel vehicles (AFVs) to their fleets. The rule required 30% of "affected alternative fuel providers" and 10% of the states' acquisitions for fleets to be in the form of AFVs beginning September 1996. These fleets are to phase in AFVs to comprise up to 90% for fuel providers in the year 2000 and 75% for states by 2001 (OGJ 4/1/96, 38). The rule applies to state government fleets in cities of more than 250,000 persons; to companies that provide alternative fuels such as electric power and natural gas; and to major oil companies. The rule excluded small refineries. No mandates were defined for local (municipal) and private fleets (other than fuel providers) in 1996. According to EPACT, these sectors will have to acquire increasing percentages of AFVs similar to state and fuel provider fleets, if the DOE Secretary determines it necessary to meet the motor fuel replacement goals of the law (Trans. Fuels 1996, 14).

In 1996, more than 352,000 AFVs were in use in the United States, an increase of 40% since 1992. Ten states had more than 10,000 AFVs in use; more than 25% of the total AFVs in use were in California and Texas. Of the AFVs in use in 1996, 75% were designed to operate on liquefied petroleum gas (LPG), primarily propane; of the non-LPG AFVs, 67.3% were fueled by natural gas, primarily compressed natural gas (CNG), and 0.7% by liquefied natural gas (LNG). Electric vehicles fueled 3.7% of the non-LPG AFVs. Privately owned AFVs comprised 71.0% of the total in 1996, with state and local governments owning 22.2% and federal fleets comprising 6.8% (Trans. Fuels 1996, 1, 2).

Consumption of alternative and replacement fuels (including oxygenates) increased by 76% from 1992 to 1996 (measured in gasoline-equivalent gallons), although traditional fuels continued to dominate U.S. vehicle fuel use. More that 90% of the total alternative and replacement fuels consumed in 1996 were in the form of oxygenates, methyl butyl ether (MTBE) and ethanol in gasoline blends. Consumption of alternative fuels increased by approximately 16 million gallons from 1994 to 1996, and it is expected that consumption of these fuels will increase by more that 45 million gasoline-equivalent gallons between 1996 and 1998 (Trans. Fuels 1996, 3,4).

Several other alternative or replacement fuels are in development. Biodiesel is one such fuel that has been undergoing testing and demonstration, particularly in heavy-duty farm equipment. Biodiesel is most commonly made from soybean or rapeseed oil and is usually mixed with diesel fuel in a ratio of 20% biodiesel to 80% diesel fuel (B20). Biodeisel as a neat fuel (100% biodiesel or B100) was designated an alternative fuel in 1996. Hydrogen as an alternative transportation fuel (ATF) is under research and development, and is considered more as a potential fuel for fuel cell applications (Trans. Fuels 1996, 25).

Natural Gas Supply

There were 24 trillion cubic feet of gross withdrawals of natural gas from wells in 1996, and marketed production at 19.8 trillion cubic feet, was 244 billion cubic feet more than in 1995. The Gulf of Mexico Federal Offshore and Texas led the production of natural gas in 1996, each producing over one-fourth of the total natural gas produced in the U.S. However, Louisiana, Texas, New Mexico, and Oklahoma remain the leading producers of natural gas, producing 15 trillion cubic feet, or 76% of the 1996 marketed production. Dry natural gas production increased 5% over 1995 production, attributed primarily to coalbed methane production in the San Juan Basin, New Mexico (Crude Oil, 1996, 31; Natural Gas 1996, 9).

U.S. proved reserves of dry natural gas in 1996 increased for the third year in a row, up approximately 1% (166,474 billion cubic feet) above 1995 levels. This does not include natural gas held in underground storage. Additions to reserves replaced 107% of what was produced in 1996. This was primarily due to higher *revisions and adjustments* to reserve estimates for old fields (lower in 1996 but higher than the last 10-year average), in addition to total discoveries, that include field *extensions*, *new field discoveries*, and *new reservoir discoveries* in old fields. Total discoveries were at the highest level in 10 years, up 12%. These occurred primarily in Texas and in the Gulf of Mexico Federal Offshore. Five major reserve areas account for 65% of U.S. natural gas reserves. These are Texas (23%), Gulf of Mexico Federal Offshore (17%), New Mexico (10%), Oklahoma (8%), and Wyoming (7%). Deepwater production technologies and improved exploration techniques enhanced the discovery and development of offshore fields and have established the Gulf of Mexico as an area of "considerable national significance" (Crude Oil 1996, 29, 30; Natural Gas 1996, 1).

Proved reserves of wet natural gas increased 1% over 1995 levels and stood at 175,147 billion cubic feet as of December 31, 1996.

Proved reserves of nonassociated (NA) natural gas (wet after lease separation) were 144,352 billion cubic feet. Production of NA natural gas in the U.S. increased by 5% (857 billion cubic feet) in 1996. As with dry natural gas, the Gulf of Mexico Federal Offshore and Texas led the production of NA natural gas in 1996, each producing over one-fourth of the total NA natural gas produced in the U.S. (Crude Oil 1996, 31).

Proved reserves of associated-dissolved (AD) natural gas at 30,795 billion cubic feet, remained approximately the same as 1995 levels. Areas with the largest volumes of crude oil reserves and production are also the areas with the largest reserves of AD wet natural gas; Texas (27%), the Gulf of Mexico Federal Offshore (20%), and Alaska (20%).

U.S. production of AD wet natural gas increased 52 billion cubic feet (2%) in 1996, with Texas producing 28% and the Gulf of Mexico Federal Offshore producing 24% (Crude Oil 1996, 31,34).

Coalbed methane (CBM) reserves increased to 10,566 billion cubic feet in 1996 and accounted for 6% of the 1996 U.S. natural gas reserves. These reserves are primarily in New Mexico, Colorado, Alabama, and Virginia. Production of coalbed methane grew by more than 5%, occurring mostly in the San Juan Basin of New Mexico and fields in southern Virginia (Crude Oil 1996, 34). New CBM technologies, such has dynamic open-hole excavation, have created wells in the San Juan basin fairway that have outperformed conventional cased and fractured completions by three to seven times. Well remediation activities on wells poorly completed in the boom years of the 1980s could add up to 550 billion cubic feet of CBM reserves by restoring activity to up to 1000 wells. Improved characterization of CBM reservoirs using advanced reservoir simulators (models) have led to successful use of new enhanced CBM (ECBM) recovery technologies and given companies the capability to greatly boost gas recovery as well. Two ECBM methods include displacement desorption using CO_2 or other strongly sorbing gases, and inert gas stripping that uses nitrogen to lower the partial pressure of methane (OGJ 1/1/96, 56–61).

Canadian imports continued to play a major role in the U.S. natural gas supply and reached a record high of 2,883 billion cubic feet in 1996, representing 12% of the total U.S. natural gas supply. Natural gas imports have risen for the 10th year in a row and now represent 13% of all U.S. consumption (Figure 10; Table 2). Canadian imports slowed in 1996 however, as pipeline capacity limits were reached, and there was only minimal expansion of this capacity. The average price of natural gas imports from Canada was $1.96 per thousand cubic feet, rebounding from the 20-year low of 1995 at $1.48 per thousand cubic feet. Exports of natural gas to Canada increased to 52 billion cubic feet, an 88% increase over 1995. This increase is attributed to more competitive pricing. Exports of natural gas to Canada represent 34% of the U.S. natural gas exports in 1996 (Natural Gas 1996, 2, 20).

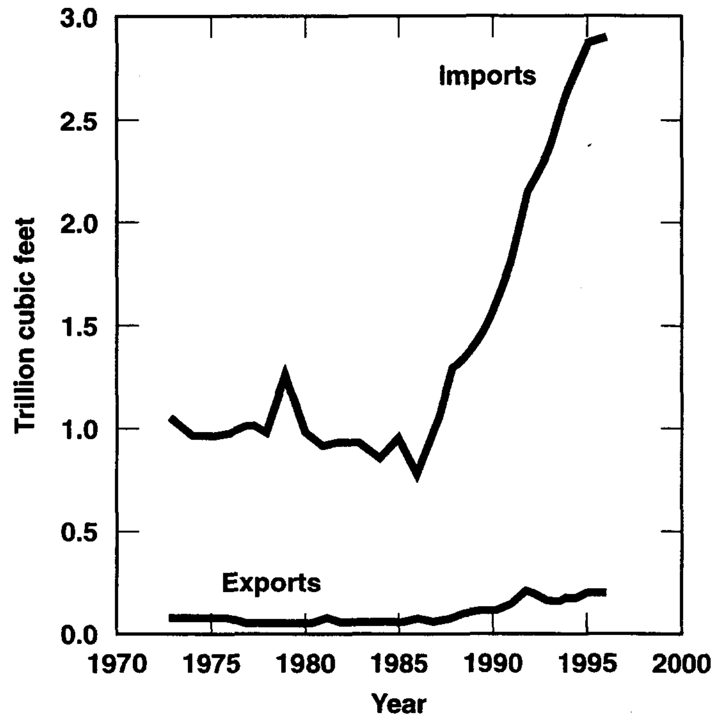


Figure 10. Growth in natural gas imports to the United States.
Source: *Annual Energy Review—1996*, DOE/EIA-0384(96), U.S. Department of Energy, Washington, DC (July 1997) Table 6.1; *Monthly Energy Review*, DOE/EIA-0035 (98/01), U.S. Department of Energy, Washington, DC (Jan. 1998) Table 4.3.

Mexico's role in the North American natural gas market has been increasing as cooperative projects have proceeded. The U.S. imported 13.9 billion cubic feet of natural gas from Mexico, more than twice the amount imported in 1995, and exported 33.8 billion cubic feet to Mexico, a sharp decline of 45% below 1995 levels. Trade across the border is affected by the circumstances of gas demand at various locations along the border and by the available infrastructure or supplies and their proximity on either side of the border. (Natural Gas 1996, p. 20)

The U.S. also made spot purchases of LNG from the United Arab Emirates indicating more flexibility in the changing world marketplace (Natural Gas 1996, 20).

Leading operators of natural gas supplies have been making changes in storage inventory management as a result of increased competition caused by regulatory reform and by new technology that increases deliverability. The consequence is that operators are maintaining lower storage volumes. The ability to store natural gas ensures supply reliability during periods of high demand. However, as underground storage has become more integrated into day-to-day operations of the pipelines and as high-deliverability storage systems have grown in capacity and utilization, the trend has been to store less, and to refine and expand locally to hold customers. The net change in storage for 1996 was 2 billion cubic feet of withdrawals (Natural Gas 1996, 2,21).

New gas pipeline projects on the U.S.–Canadian East Coast and in the U.S. Rocky Mountains progressed. Proposed is a 630-mile pipeline system to deliver gas from the Sable Island area off Nova Scotia to customers in southern Maine and New Hampshire. Another 800-mile pipeline system is planned to extend from southwest Wyoming to central Nebraska. In 1996, plans existed for more than 3,800 miles of gas line to be laid in the U.S. and another 2,800 miles in Canada (OGJ, 2/19/96, 22).

The Gulf of Mexico currently has 14,773 miles of natural gas pipeline—91% in federal water and the rest in state water—20% of which has been laid in the last 5 years. Another 775 miles of pipeline is expected in the Gulf, which now provides U.S. markets with 26% of domestic gas supplies and holds 18% on the nation's gas reserves. Approximately 48 trillion cubic feet of natural gas reserves are believed to exist in the Gulf of Mexico (OGJ 2/19/96, 23).

Natural Gas Demand

Consumption of natural gas by residential, commercial, and industrial consumers set new records in 1996, continuing an upward trend since 1991 (see Fig. 11) . At 22 trillion cubic feet, U.S. consumption of natural gas accounted for 25% of the total energy consumption in 1996. Residential consumption was 8% higher in 1996 than in 1995 at 5.2 trillion cubic feet, accommodating nearly 1 million new customers. This was driven primarily by weather-related demand; heating degree data shows that 1996 was on average 14% colder than normal, and March was 27% colder in 1996 than 1995. Some parts of the U.S. were 30- 60% colder in March 1996 than one year previous. Commercial consumption reached 3.2 trillion cubic feet, a 4% increase over 1995 levels. Industrial consumption, which includes deliveries to all nonutiltiy power producers (NPPs), was 8.9 trillion cubic feet, a 3% increase over 1995. In recent years, this sector has consumed more than 40% of the natural gas delivered to customers. Delivery data show that a large share can be attributed to consumption by NPPs, of that large share, a major portion is being used for cogeneration, i.e., for production of both electricity and process heat. Natural gas comprised 8% of electric utilities consumption for electricity generation in 1996, decreasing 460 billion cubic feet, or 15% from the previous year (Natural Gas 1996, 2,35,36).

Prices for natural gas rose sharply in 1996, rebounding from the low prices in 1995. Prices paid by gas distribution companies rose 18% from 1995 to 1996 (from $2.78 to $3.27 per thousand cubic meters). This price reflects all charges for the acquisition, storage,

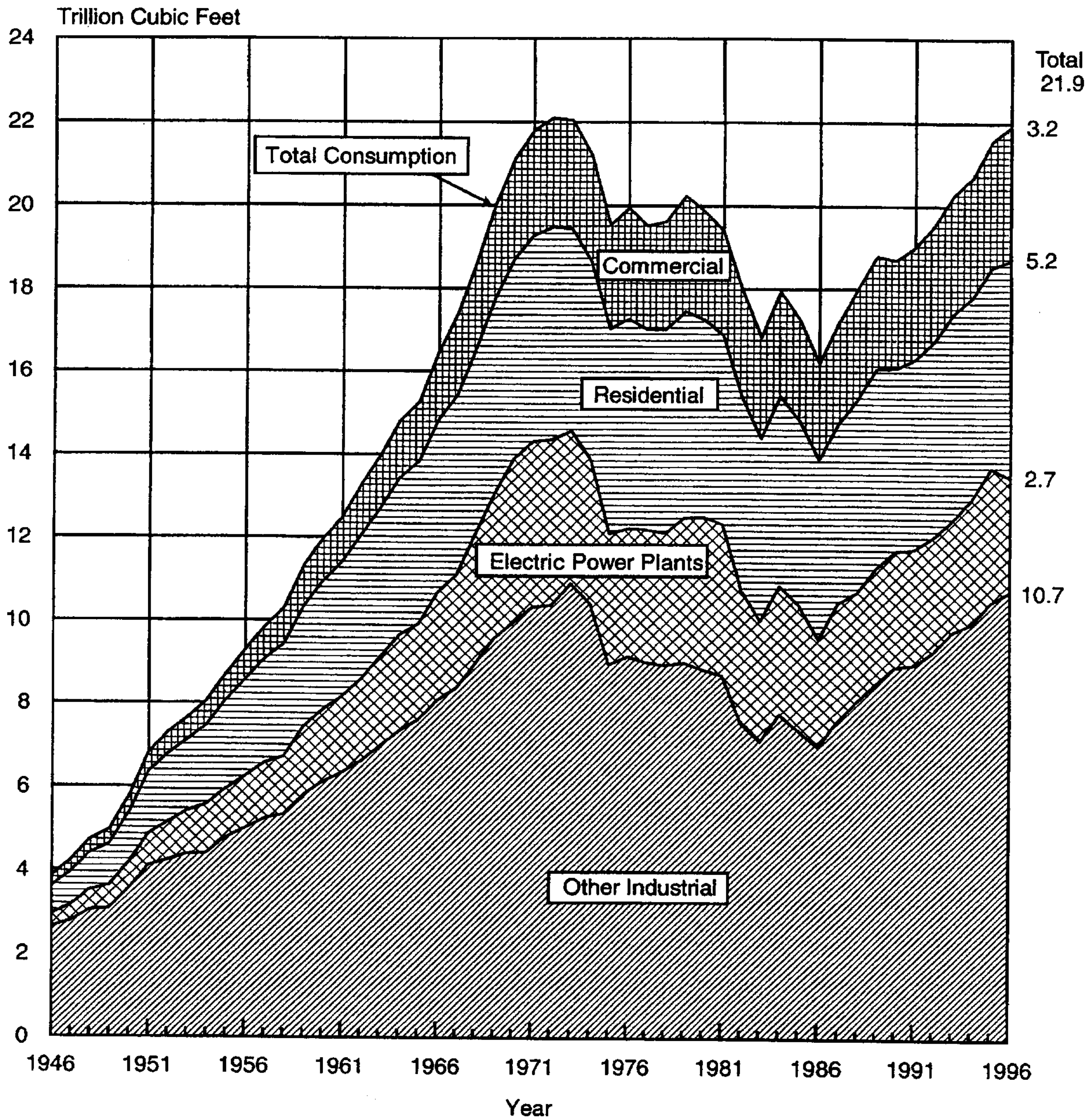


Figure 11. Consumption of natural gas in the U.S. by end-use sector.
Source: *Twentieth Century Petroleum Statistics 1997*, 53rd Ed., DeGrolyer and MacNaughton, Dallas, Texas (Nov. 1997), Chart 84.

and transportation of gas and other charges associated with the local distribution companies obtaining the gas for sale to customers. Residential customers, the sector that pays the highest price for natural gas, saw only modest changes in price, paying $6.34 per thousand cubic feet in 1996 compared to $6.06 in 1995. This 1996 price however was 1% lower than the 1994 price. Commercial customers pay the second highest price for natural gas and paid an average of $5.40 per thousand cubic feet in 1996, a 7% increase over 1995. Prices paid by industrial customers rose 26% in 1996, reaching $3.42 per thousand cubic feet. Natural gas for vehicle fuel, principally deliveries to refueling stations for fleet vehicles, rose to $4.34 per thousand cubic feet. The price paid by electric utilities for natural gas saw the highest increase of all sectors, 33%, increasing from $2.02 to $2.69 per thousand cubic feet. The price to electric utilities does not include NPPs (Natural Gas 1996, 51,52).

Coal Supply and Demand

Coal production in the United States totaled 1,064 million short tons in 1996, approximately 3% higher than 1995 levels. Bituminous and subbituminous accounted for 91%, and lignite and anthracite accounted for the remaining share (AER 1996, 203). Coal production east of the Mississippi accounted for 53% of all the coal produced in the U.S. in 1996 (564 million short tons) in spite of the fact that the Eastern states had a net loss of 192 mines (Coal 1996, xi). However, growth in coal production in the West has increased by a factor of 19 over the last 30 years. This is in part a result of environmental concerns that increased the demand for low-sulfur coal, which is concentrated in the West (AER 1996, 203).

Coal productivity has increased over the last 10 years by 6.3%. Average productivity in 1996 was 5.7 short tons per miner per day compared to 5.4 short tons per miner per day in 1995. The leading coal producing states were Wyoming, West Virginia and Kentucky (Coal 1996, 59).

Coal has been the main energy export of the U.S. since World War II, peaking in 1981 at 113 million short tons. Although fluctuations have occurred, coal exports are up from the 1994 low of 71 million tons to 91 million tons in 1996, an increase of 27%. Canada, Japan, and Italy are the three largest foreign purchasers of U.S. coal (AER 1996, 204). Steam coal exports rose 3% in 1996 to 38 million tons. US. metallurgical coal exports increased 2% from 1995, to 53 million short tons. West Virginia dominated coal exports, shipping over 42 million short tons. Approximately 75% went to overseas metallurgical markets (Coal 1996, xii).

Imports of coal into the U.S. in 1996 were about the same as in 1995, at 7 million short tons, received primarily from Indonesia, Canada, Venezuela, and Colombia (Coal 1996, ix).

The DOE/EIA estimates that there were 494 billion short tons of coal reserves at the beginning of 1996, 2 billion short tons less than in 1995 (AER, 1996,105; AER 1995,109). Coal producers, distributors, and major consumers (e.g., electric utilities and coke plants) commonly maintain large stockpiles of coal because production can vary with weather and coal miner's strikes. Stocks of coal were 8% lower in 1996 as a result of large drawdowns by electric utilities. In 1996, 74% of U.S. coal stocks were held by electric utilities. Prices of coal at electric utilities has steadily dropped from the peak of $49.80 per short ton in 1982 to $24.11 per short ton in 1996 (AER 1996, 204).

Consumption of coal in the U.S. reached 1,006.2 million short tons in 1996, a record reflecting increased use of coal for electricity generation. Consumption by electric utilities reached 84% in 1996, and 2.4% was consumed by independent power producers. All other sector consumption has been in an overall decline since 1949 (Fig. 4–7). Most of the remaining coal consumed was for coke plant use and "industry and miscellaneous" use (manufacturing plants, large commercial establishments, agriculture, mining and construction industries, and transportation), at 3% and 7% respectively. Residential and commercial consumption was 6.0 million short tons (0.6%) (AER 1996, T. 7.3).

DOE opened a new era for clean energy from American coal through its Clean Coal Technology Program (CCTP), a public/private partnership that began in 1986. Initially, the mandate of this program was to expand the options for pollution control to reduce the release of acid rain pollutants. Many of the environmental retrofit technologies, such as low-polluting coal burners and post-combustion sulfur-removing devices, have moved to commercial application. A decade later, this program had broadened its objectives and included an array of high-tech concepts that will lead the way for the next generation of super-clean, high-efficiency power plants. The emphasis is on high efficiencies because higher coal-to-electricity efficiencies are the most cost-effective way to reduce carbon dioxide releases. One of the most promising technologies to come out of the CCTP is integrated gasification combined-cycle (IGCC) power generation. In 1996, DOE started operations to demonstrate this technology on a 262-MW unit at the Wabash River Generating Station, West Terre Haute, Indiana. This technology has since demonstrated that it can remove more than 99% of the sulfur in high-sulfur coal as well as reduce nitrogen oxide emissions to levels below air-quality standards. Because coal will most likely supply more than 50% of U.S. electricity well into the next century, IGCC will be one of the predominant technologies of the 21st-century generation of coal-fired power plants. Other candidate technologies include the "Carefree™ Coal" and "Self-Scrubbing Coal™," a coal-fueled diesel engine, Rosebud Syncoal® advanced coal combustion, fluidized bed technology, and methanol production from coal-demand gas using advanced liquid phase synthesis (DOE 1998).

The importance of coal as a fuel for the future cannot be underestimated. Coal will continue to be the primary baseload fuel well into the 21st century. Coal contributes approximately $21 billion per year to the U.S. economy, with an added indirect contribution of $132 million. Coal exports are expected to rise from 90.5 million tons in 1996 to 130 million tons in 2015. By using today's Clean Coal Technologies, emissions of CO_2 can be reduced by approximately 30%, and smog and acid rain can be brought to negligible levels by 2010. An investment of $1.4 trillion will be required to produce the 1,190 GW of new power capacity that will be needed worldwide over the next 15 years. It is expected that half of this investment will be for coal-fired power plants. Thus, clean coal technologies are expected to play a significant role in the future with growing demand both domestically and internationally (Clean Coal 1996, 10–15).

Renewable Energy Consumption

Renewable fuels include conventional hydroelectric power, biofuels, geothermal energy, solar energy, and wind energy. Renewable energy consumption reached 7.4 quads, or approximately 8% of the total U.S. energy consumption in 1996 (Fig. 12). Hydropower contributed the largest share, approximately 53% of the renewable energy consumed in the U.S., and biomass, the second largest contribution, at 41%. Consumption of renewables also increased 8% over 1995 levels. Since 1991, renewable energy consumption has increased at an annual rate of 2.2% per year. Net renewable imports (0.3 quad) comprised of hydroelectric and geothermal energy rose 17% in 1996 primarily due to higher hydroelectric imports and lower hydroelectric exports. (REA 1997, Vol.1, 5, 6)

Distribution of renewable energy consumption in 1996 by sector was as follows: electric utility, 53% (3.9 quads); industrial, 37% (2.7 quads); residential and commercial, 10% (0.7 quad); and transportation, 1% (0.1 quad). Approximately 90% of the renewable energy consumed by electric utilities was hydropower, and another 8.5% was from net imports of electricity. Excluding imported renewable-based electricity, utilities generated 433 billion kWh or 12% of total electricity generation using renewables; excluding hydropower this percentage was 2%. Biofuels-generated electricity reached 64,074 kWh.

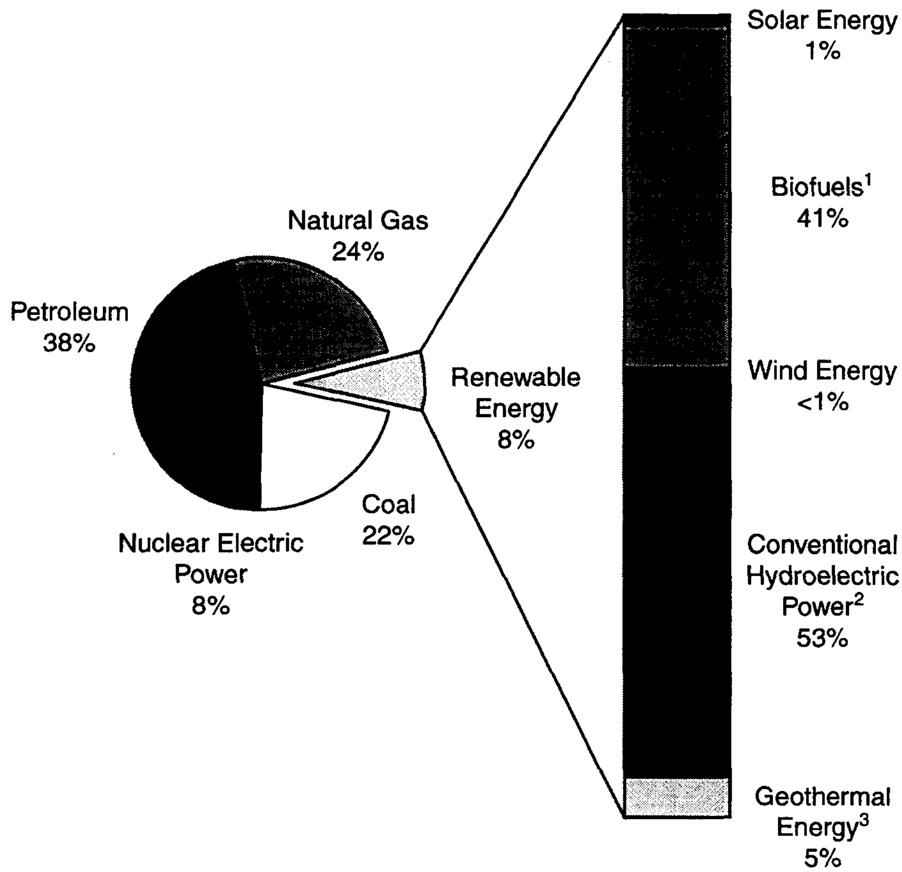


Figure 12. Renewable energy consumption as a share of total energy, 1996.
Source: *Annual Energy Review 1996*, DOE/EIA-0384(96), U.S. Department of Energy, Washington, DC (July 1997) Fig. 10.1.
[1] Wood, wood waste, peat, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste.
[2] Includes electricity net imports from Canada that are derived from hydroelectric power.
[3] Includes electricity imports from Mexico that are derived from geothermal energy.

State policy and resource availability are the primary determining factors that govern where renewable electricity is generated. The leading producer of renewable-generated electricity is Washington, producing 27% of all the nation's renewable energy as a result of it's access to water power. California is the second-largest producer of renewable generated electricity. California's energy policies provide tax credits that promote the use of renewable energy. California utilities produce 16% of the nation's renewable electricity and is the second-largest producer of renewable energy and it's share of nonutility renewable electricity is almost 25%. California also has most of the Nation's developed geothermal energy resources in addition to having "significant" wind, solar, biomass (wood and waste), and hydroelectric resources. Oregon has significant water-power resources making it the third-largest producer of renewable energy. Only New York utilities (at 8%) generated more than 4% of electricity generated in the U.S. from renewables (REA 1997, Vol.1, 8–10).

Hydropower

Conventional hydroelectric power consumption in 1996 was 3.9 quads, a 13% increase over 1995. Consumption of this resource by the industrial and the electric utility sectors was 0.2 quad and 3.4 quads respectively. Almost 90% of the electric utility consumption of renewable resources was hydropower, producing 332 billion kWh (3.7 quads) of electricity (REA 1997, T.4; AER 1996, T. 10.2). Consumption of hydropower by the industrial sector, including NPPs, cogenerators, independent power producers, and small power producers, was for electricity generation producing approximately 17 billion kWh (0.17 quad) of electricity (AER 1996, 261, T. 10.2).

Biomass and Other Renewables

Biofuels are defined as nonfossil biomass energy sources (e.g., fuelwood, waste wood, garbage, and crop waste) that are burned or gasified to produce heat or electricity. "Biomass-derived fuels" include wood byproducts, refuse-derived fuel, ethanol, and methanol, resulting from processing biomass energy sources. Biomass-derived fuels may be byproducts of industrial or agricultural processes or fuels made from biomass feedstocks (AER 1996, 261).

Excluding hydropower, biofuels accounted for 87% of the renewable energy consumption in 1996 at 3.0 quad, most of which was wood energy (2.4 quads) (REA 1997, Vol.1, T. H1; AER 1996, 261). Biomass energy consumption increased 2.4% in 1996 over the previous year, and accounted for 87% of non-hydro renewable energy consumption. Approximately 22% of biomass consumption was used for electricity generation and the rest was used to provide industrial heat. Biomass-generated power increased to 64,074 kWh in 1996. The industrial sector consumed the largest share of biofuels in 1996 at 76% or 2.3 quads representing a 50% increase since 1990. The residential/commercial sector consumed 0.6 quads, unchanged from 1995; the transportation sector consumed 0.1 quad primarily as ethanol blended into gasoline, and the electric utility sector consumption was 0.02 quad (REA 1997, Vol.1, T. H1, T. 2, 6,7).

Use of municipal solid waste (MSW) as an energy source grew rapidly during the 1980s as a result of public policy at local, state and federal levels that promoted the construction of waste-to-energy facilities. However, in the 1990s environmental policies have encouraged recycling and require expensive pollution control systems on waste-to-energy facilities. This fact in addition to changes in federal tax policies and competitive pressures from deregulation have created much uncertainty over protection of capitol investments in this type of facility. As electricity prices drop, waste streams are sent to the cheapest disposal option which is usually out-of-state landfills. Nevertheless, MSW-derived energy increased 18 trillion Btu annually between 1990 and 1996. In 1996, MSW energy consumption was estimated to be 421 trillion BTU. Other sources of waste-derived energy are refuse-derived fuel, and methane recovered from landfills. Consumption of all waste-derived energy 1996 reached 503 trillion Btu in 1996 (REA 1997, Vol. 1, 15).

Other biofuels such as corn are used to make ethanol; soy beans, animal tallow, and used cooking oil are used to manufacture biodiesel. Between 1990 and 1996 ethanol production from corn (2.5 gallons per bushel of corn) increased, but in 1996 corn prices increased beyond break-even levels for manufacturers, causing production of ethanol from corn to drop 29% in 1996, from 104 trillion Btu in 1995 to 74 trillion Btu in 1996. Biodiesel, a substitute for petroleum diesel, is manufactured using one bushel of soy beans to produce 1.5 gallons of biodiesel (7.3 lbs./gal.). Also, a mixture of 65% animal tallow with 35% ethanol can be blended with No. 2 diesel at a 20:80 ratio yielding a fuel that has the same viscosity as diesel. Total consumption of biodiesel in 1996 was approximately one million gallons (REA 1997, Vol.1, 13,15, T. 8).

Geothermal energy produced 4.8% of the renewable energy in 1996. Geothermal energy can be used directly for space heating or converted to electricity. Industrial and electric utility sectors were consumers of geothermal energy, consuming 0.2 quad and 0.1 quad respectively. Together the two sectors produced 16,249 million kWh of electricity. An additional 645.5 million kWh of electricity was generated from geothermal imports. Excluding hydropower, approximately 73% of the electricity produced by the electric utility sector from renewables was from geothermal power (REA 1997, Vol.1, T.4). There are currently two geothermal plants operating in the United States, one in California and one in Utah. Geothermal energy consumption dropped in 1995 to 0.33 quad from 0.38 quad in 1994, primarily due to production problems at The Geysers, a utility-owned facility in California. However, production at The Geysers in 1996 reversed a 10-year decline, increasing from 4,606 million kWh in 1995 to 5,043 million kWh in 1996, a 9.5% increase (REA 1997, Vol.1, 16). One new site of potential geothermal resources has been identified and is currently undergoing environmental review for the construction, operation and maintenance of two geothermal power plants. The project area is 13,725 acres of federal geothermal leases located on the Klamath and Modoc National Forests, near Mount Shasta, Siskiyou County, CA (REA 1997, Vol.1, 16). The Four-Mile Hill (a.k.a. Glass Mountain) Geothermal Project, if approved, would be a 49.9 MW (gross) dual-flash geothermal power plant. Final decision of the Environmental Impact Statement (EIS) is expected in June of 1998. The second proposed project known as the Telephone Flat Geothermal Development Project, would be a 48 MW dual-flash geothermal power plant. Release of the draft EIS was scheduled for May 1998. If approved, both projects are expected to go on-line in 1999 (USDA 1998).

The market for the production of energy from wind saw a turbulent year in 1996 when the largest U.S. manufacturer of turbines, Kenetech Windpower, filed bankruptcy, and plans in California to provide an additional 1,000 MW of capacity folded. Nonetheless, even though 1996 was a slow year for wind energy development, gross generation from wind increased by 10% between 1995 and 1996. Two new projects came on-line in 1996 adding 4% to the total U.S. electric-generating capacity from wind power that in 1996 reached 1,801 MW. Two new projects are proposed in the midwest; one 100 MW plant in Minnesota, and a second in Iowa for a 112.5 MW wind capacity (REA 1997 Vol.1, 17).

Solar electric generating capacity in 1996 was 333 MW, unchanged over the last three years. All sectors utilized solar energy except the transportation sector (REA 1997, Vol. 1, 9). 65 trillion Btu (87%) of the 75 trillion Btu of solar energy supplied in 1996 was utilized by the residential and commercial sector; 9 trillion Btu was consumed by the industrial sector, and 0.5 trillion by electric utilities (AER 1996, 261). Most solar energy was used off-grid, in remote areas where electric transmission lines are unavailable. The latest statistics from the DOE/EIA show that nonutility gross generation from solar was 824,193 million kWh while the electric utility net generation from solar was 3,909 million kWh. Electric utilities claim that 2.7 million kWh of net electricity was generated from photovoltaic modules alone in 1996, and 90% of that was generated in California (REA Vol.1, 1997, T. 9, 17).

Electrical Supply and Demand

Net generation of electricity by electric utilities and non-utility power producers totaled 3,447 billion kWh in 1996, an increase of 2.7% over 1995 levels. Electric utilities increased their net generation in 1996 by 2.7%, generating 3,077 billion kWh, 89% of the U.S. electricity supply. Continuing a trend of many years, the largest portion of generated electricity came from coal: 1,796 billion kWh, or 52% of the total. Nuclear power generated the second largest share at 675 billion kWh (20% of the total), down from 1995. Natural gas contributed 456 billion kWh (13%) and hydroelectric contributed 347 billion kWh (10%) in 1996. Electricity imported across U.S. borders with Canada and Mexico totaled 47 billion kWh. Conventional hydroelectric generation increased 12% above 1995 levels due to increased water stored behind dams, particularly in the Pacific Northwest, which provided 56% of the total U.S. hydroelectric generation for 1996 (AER 1997, T. 8.1, 8.2).

Cold weather increased demand for natural gas and electricity in 1996, particularly in the Midwest where heating requirements were high. This increased demand for natural gas for heating drove up the prices for gas more than 30% during the winter months of 1996, causing power generators to switch to coal to meet their fuel requirements (EGG 1996, 13). As a result, gas-fired generation declined by 15% from the record-high levels reported in 1995 (EPA 1996, 2).

Generating capability (net summer capability) at electric utilities in the U.S. totaled 709.6 MW in 1996. This total includes 4.4 MW of added capability since 1995, 35% of which was coal-fired and 27% was both natural gas and nuclear (EPA 1996, Vol.1, 1). Based on primary energy source, generating capability had the following distribution: coal-fired totaled 302.2 MW; natural gas totaled 17.9 MW; dual-fired (petroleum and natural gas) totaled 144.2 MW; nuclear totaled 100.7 MW; renewables totaled 77.4 MW; petroleum totaled 46.1 MW; and hydroelectric totaled 96.3 MW (conventional and pumped storage) (AER 1996, T. 8.2; EPA 1996, 1).

Electricity produced by NPPs has steadily increased over the past decade. The energy crisis of the 1970s coupled with inflation and the high cost of nuclear power led to a reexamination of alternative sources of power and stimulated the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 plus other legislation that encouraged the growth of the nonutility industry (EPA 1996, 1). In 1996, NPPs net generation of electricity was 403 billion kWh, an increase of 41% since 1992 compared to utilities growth of 10% since 1992.

Generating capability (net summer capability) at NPPs in the U.S. totaled 66.1 MW. Based on primary energy source, generating capability had the following distribution: coal-fired totaled 10.0 MW; natural gas totaled 25.7 MW; dual-fired (petroleum and natural gas) totaled 9.2 MW; renewables totaled 14.9 MW; petroleum totaled 3.0 MW; and hydroelectric (conventional only; no pumped storage) totaled 3.3 MW. (AER 1996, T. 8.2)

Electric utilities consumption of fossil fuels for the generation of electricity were as follows: 873.7 million short tons of coal (17.9 quads), 2,736.6 billion cubic feet of natural gas (2.8 quads), and 118.2 million barrels of petroleum (0.7 quads) for a total of 21.4 quads of fossil fuels consumed (AER 1996, T. 8.2).

Retail sales of electricity were greatest to the residential sector in 1996 at 1,082 billion kWh. Sales to the industrial sector were nearly as great, totaling 1,030 billion kWh. The commercial sector purchased 887 billion kWh and approximately 98 billion kWh was sold to "other" categories, e.g., street and highway lighting, sales to public authorities, railroads and railways, and interdepartmental sales. Retail prices in real dollars (chained (1992) dollars) of electricity have been steadily decreasing for both the residential and commercial sectors since 1982, with the residential sector paying 7.7 cents per kWh and the commercial sector, 6.9 cents per kWh. Prices paid by the industrial sector have also been decreasing since 1982, and this sector paid 4.2 cents per kWh in 1996 (AER 1996, 224).

As noted in previous issues of this report, the production of energy from fossil fuels has been affected by environmental legislation addressing air quality problems in the U.S. The Clean Air Act Amendments of 1990 and Title IV of the Act (Phases I and II) are intended to curtail problems of acid rain caused by sulfur dioxide and nitrogen oxides emissions from fossil-fueled electric power plants (and to a lesser extent from industrial and transportation sources.) Phase I runs from 1995 to 1999, and affects 261 generating units ("Table I units"), most of which are coal-fired units with relatively high emissions. The EPA has allowed another 174 units to participate in Phase I as compensating units in a utilities Phase I compliance plan. Thus Phase I affects 435 generating units powered by boilers. More than 2,000 units will be affected by Phase II. Estimated costs of compliance with Phase I, annualized and industry-wide, were $836 million in 1995 dollars, which represents 0.6% of the $151 billion electric operating expenses of investor-owned utilities in 1995. Although this percentage is small, costs ranged from a low of $16.39 per kilowatt to $208.90 per kilowatt. Thus, there has been a push for the use of low-sulfur subbituminous coal over high-sulfur bituminous coal. Modifying coal-fired plants to handle low-sulfur coal has been estimated at $113 per ton of sulfur dioxide removal whereas the use of scrubbing systems cost approximately $332 per ton of sulfur dioxide removal. Fifty-two per cent of the Table I units chose fuel switching and blending in 1995 as the preferred option in reducing emissions, resulting in 59% of the reduction of sulfur dioxide emissions in 1995 compared to 1985, i.e., 9.9 million tons reduced to 4.4 million tons. Fuel switching has also boosted low-sulfur coal sales in the U.S. Some utilities plan to overcomply with Phase I requirements in order to meet the more stringent Phase II requirements, e.g., installing scrubbers now rather that selecting the cheaper option. Other options include: obtaining additional allowances, using previously implemented emissions controls, retiring units, boiler repowering, substituting Phase II units for Phase I units, and compensating Phase I units with Phase II units (CCA 1997).

Energy use projections note that the generation of electricity from both natural gas and coal is expected to increase significantly through the year 2015 to meet increased demand and to offset the decline in nuclear power generation. By 2016, many of the nuclear reactors will be at the end of their 40-year operating license, retiring 38 GW of the 100 GW of nuclear capacity available in 1996. Only one new nuclear unit, Watts Bar I, was completed in 1996, and no other units are identified to come on line. Improved performance of existing reactors is expected to raise nuclear generation through 1999 and steadily decline as reactors retire. Coal is expected to remain the primary fuel for electricity generation providing 50% of the generation (excluding cogenerators) in 2015. Consumption of natural gas is expected to increase 1.7% per year due to the growth in gas-fired electricity generation (AEO 1997, pp. 3,4). Although energy demand in the future will increase, the increase per capita is expected to be offset by efficiency gains and remain relatively level through 2015 (AEO 1997, 5).

Table 3. Installed capacity and gross generation of NPPs larger than 5 MW and 1 MW for years after 1992.

Year	Installed capacity (GW)	Increase (%)	Gross generation (billion kWh)	Increase (%)
1989	36.6		187.1	
1990	42.6	16.1	215.2	15.0
1991	48.2	13.2	248.5	15.5
1992[a]	56.8	17.8	296.0	19.1
1993	60.8	7.0	325.2	9.9
1994	68.4	12.6	355.0	9.1
1995[R]	70.3	2.6	374.4	5.5
1996	73.2	4.7	382.5	1.8

Source: "Statistics on Nonutility Power Producers," Reprinted from *Monthly Energy Review* (Aug. 1992 data) (Oct. 1992); *Electric Power Annual—1996,* Vol. 2, DOE/EIA-0348(96)/2, US Department of Energy, Washington, DC (February 1998) Executive Summary on-line.

[a] Through 1991, only nonutility electric generators larger than 5 MW were included in the data provided in Table 3. Starting in 1992, nonutility electric generators larger than 1 MW have been incorporated into the data.

[R] revised

Deregulation and Restructuring of the Electric Power Industry

Restructuring of the U.S. electric power industry ($200 billion in annual sales) began in 1978 when Congress enacted the Public Utilities Regulatory Policy Act (PURPA) enabling qualifying nonutility generators to enter the wholesale power market and mandating that utilities buy electricity—energy and capacity—from nonutilities at avoided cost. Driving these changes was a desire to reduce fossil fuel consumption through use of cogeneration, renewables, and more efficient generators that could be built quickly and more cheaply than older plants. Large industrial customers in states with high electricity prices have lobbied for restructuring as a means of lowering prices.

The Energy Policy Act of 1992 (EPACT) opened access to the transmission network and exempted certain nonutilities from the provisions of the Public Utilities Holding Company Act of 1935 (PUHCA) which kept nonutilities out of the wholesale market.

On April 24, 1996, the Federal Energy Regulatory Commission (FERC), an independent regulatory agency within the U.S. Department of Energy, issued FERC Orders 888 and 889 designed to encourage wholesale competition in the generation of electric energy by separating transmission from generation, marketing, and communication functions and by eliminating monopoly power over transmission. Transmission and distribution of electricity remain regulated and non-competitive.

FERC Order 888 opened transmission access to non-utilities and thereby established wholesale competition. Utilities must file open, nondiscriminatory tariffs for transmission. FERC Order 888 also allows utilities to recover "stranded assets," costs that utilities incurred under the old regulatory framework but which cannot be recovered from consumers in an open, competitive market. (The method of recovery of stranded costs selected by FERC is direct assignment of costs to customers that leave their utility and look elsewhere for electric energy).

FERC Order 889 requires electric utilities to establish electronic means of sharing information with nonutilities, on a real-time basis, about the availability of transmission capacity (EIA 2/98).

California

In December 1995, the California Public Utilities Commission (CPUC) narrowly adopted a compromise plan for electricity deregulation. It provided for a 5-year transition, beginning in 1998, to an open, deregulated market by 2003. Large customers would have direct access to electricity suppliers in 1998, and by 2003 all customers could choose a supplier. But the CPUC plan was widely viewed as inadequate.

In 1996, the California legislature enacted Assembly Bill 1890 (Brulte, R-Rancho Cucamonga) to provide an open, competitive electricity market where customers can pick and choose their power company. AB 1890 was fashioned over the summer months by a two-house conference committee chaired by Senator Steve Peace (D-Chula Vista). AB 1890 built upon the CPUC plan but provides more specificity and earlier benefits to small customers. As with the CPUC plan, the legislation provides a transition period, beginning on January 1, 1998, to full competition after five years. AB 1890 mandates an immediate 10% reduction in rates for residential and small business customers to be financed by bonds and proponents of the bill project an eventual 20 % reduction in rates. Large business and industrial customers hope to see their rates reduced by 30 % when the transition to a competitive market is completed.

AB 1890 allows investor-owned utilities to pay-off $28 billion of stranded assets over five years with a non-bypassable Competitive Transition paid by all customers, however the legislation also places a cap on stranded cost recovery. The legislature added a $500 million subsidy, administered by the California Energy Commission, to help make alternative sources more competitive and provided over $60 million per year for Public Interest Energy Research.

The impetus for deregulation came from large manufacturers and large businesses who complained that rates in California were 50% above the national average. AB 1890 had wide, but not universal, support among industry, labor, energy producers, environmentalists, and the utilities.

Under the California plan, only generation—not transmission or distribution—is deregulated. Electricity suppliers can market directly to customers or they can bid to supply power to utilities through the Power Exchange which creates a spot market for electricity, matching buyers and sellers.

Operation and reliability of the electric transmission system within California will be the responsibility of the Independent System Operator (ISO) which will be regulated by the FERC. Electricity distribution will continue to be owned and operated by the utilities and remains regulated (California Journal 11/1996).

Other States

Recovery of stranded costs was seen as a key issue in states where planning for deregulation has begun. The Arizona Corporation Commission (ACC) and the Alabama Legislature adopted provisions for recovery of some, but not necessarily all, stranded costs through exit fees. The ACC also issued a final order to phase-in retail access over the period 1999 to 2003.

The Colorado Public Utilities Commission surveyed stakeholders on retail competition and issued a report on restructuring. In Illinois, two utilities conducted retail wheeling pilot programs (EIA web).

Nuclear Power

Power Plant Operations

In 1996, there were 110 operable commercial nuclear power units with full-power licenses issued by the U.S. Nuclear Regulatory Commission with a total net capacity of 100,685 MWe. Together, these plants produced 674.7 TWh (net) of electric energy (up 0.2% from 673.3 TWh in 1995) for an average capacity factor of 76.4% (down from 77.5% in 1995 when there were 109 plants on line). Nuclear energy accounted for 22% of the total electric energy generated by utilities in 1996 (down from 22.5% in 1995). Electricity generation from nuclear energy is shown in Table 4.

Table 4. Electricity generation from nuclear energy.

	Year				
	1992	**1993**	**1994**	**1995**	**1996**
Total utility electricity generation (billion kWh)	2797.0	2883.0	2911.0	2995.0	3077.0
Nuclear contribution (billion kWh)	619.0	610.0	640.0	673.0	674.7
Percent nuclear	22.1	21.1	22.0	22.5	21.9
Installed nuclear capacity[a] (GWe)	99.0	99.0	99.1	99.1	100.7
Number of operable reactors	109.0	109.0	109.0	109.0	110.0
Annual nuclear capacity factor (%)	70.9	70.5	73.8	77.5	76.4

Source: *Monthly Energy Review*, DOE/EIA-0035 (97/07) U.S. Department of Energy, Washington, DC (July 1997) Sec. 8.
a. Net summer capability of operable reactors

The Tennessee Valley Authority's Watts Bar-1, a 1,177-MWe pressurized water reactor went critical on January 18, 1996, and operated at up to 5% power under a low power license issued by the NRC in November 1995. Watts Bar-1 is the last nuclear power plant under construction in the United States. TVA announced that it would spend 18–24 months considering its options for the partially completed Watts Bar-2 and Bellefonte-1 and -2 plants. If a partner cannot be found to finish these plants, conversion to natural gas is a possibility (NN 2/96, 17). The plant reached full power on May 9, 1996, (NN 6/96) started commercial operation on May 27, and operated at a 98% capacity for over 100 days (NN 10/96, 13).

Data compiled by the Institute of Nuclear Power Operations (INPO) for U.S. nuclear power plants in 1996 show median unit capability factor at 82.5%, almost unchanged from 82.6% in 1995. INPO also reported continued improvement in nuclear fuel reliability, thermal efficiency, reduction of collective radiation dose to workers and reduction of low-level radioactive waste volumes (NN 5/97).

As an element of the government's program to minimize proliferation risks, the DOE announced plans to blend down the surplus high-enriched uranium from its nuclear weapons program and make available for sale by the U.S. Enrichment Corporation as low enriched uranium that could be used as power plant fuel (Federal Register 8/5/96, 40618)(NN 9/96, 14).

Storage and Disposal of High Level Nuclear Waste and Spent Fuel

At the start of 1996, the nuclear industry hoped that a private spent fuel storage facility would be built and operated on the Mescalero Apache reservation in New Mexico. Plans called for a facility to store 20,000 metric tons of heavy metal for 20 years beginning in 2002 with a possible expansion to store 40,000 tons for 40 years. Delivery of spent nuclear fuel would be by rail only (NN 1/96). However, in March of 1996, after 24 months of negotiations, talks between utilities and tribal leaders were broken off (NN 5/96, 14).

In Congress, the Nuclear Waste Policy Act of 1996, S. 1271 (Craig, R-Idaho), and a companion measure, H.R. 1020 (Townes and Upton), had been introduced in 1995. These bills direct the DOE to construct and operate a centralized site for interim storage of spent fuel adjacent to the proposed Yucca Mountain disposal site by November 30, 1999. DOE stated that a permanent disposal facility would not be ready until 2010 at the earliest (NN 2/96, 18). The Senate Energy and Natural Resources Committee approved S. 1271 on March 13,1996 by a vote of 12–6. The White House promised that any bill naming the State of Nevada as the host of an interim storage facility would be vetoed (NN 4/96, 13). Despite the veto threat, the Senate approved an amended version of the proposed Act, S. 1936, by a vote of 63–37 (NN 9/96, 34).

On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision that DOE is obligated to accept spent nuclear fuel by January 31, 1998. The Court rejected DOE's arguments that it is not obligated to accept spent fuel from commercial power plants if a repository is not yet in operation (NN 8/96).

The Nuclear Waste Technical Review Board's annual report, "Report to the U.S. Congress and the Secretary of Energy: 1995, Findings and Recommendations" praised the DOE for progress in characterizing the proposed spent fuel repository site at Yucca Mountain, Nevada. "If recent progress can be maintained, the Board believes that a site-suitability decision can be made within five years..." The Board called for "...adequate and stable funding...to achieve this objective"(NN 7/96).

A team of researchers in the Department of Nuclear Engineering at the University of California, Berkeley studied the possibility of migration of nuclear waste at the proposed Yucca Mountain, Nevada repository and the potential for an uncontrolled chain reaction and explosion. The "exploding waste" theory had drawn considerable attention when it was suggested as "possible" by Los Alamos National Laboratory researchers in 1995. Professor William Kastenberg, Department Chairman and leader of the Berkeley study team summarized the group's conclusions: "...at the Yucca Mountain site, there don't appear to be any geochemical or geophysical mechanisms for these supercritical scenarios to happen." The group's report suggested several engineering features to reduce to virtually zero the possibility of a supercritical waste configuration.

The EPA took an important step toward eventual approval of the Waste Isolation Pilot Plant (WIPP) in New Mexico, for disposal of transuranic wastes (TRU) when it issued a final rule with criteria for determining the project's compliance with EPA's radiation protection standards, *Criteria for the Certification and re-Certification of the Waste Isolation Pilot Plant's Compliance with the 40 CFR Part 191 Disposal Regulations (Federal Register,* Feb. 9, 1996, 5224-5245) (NN 5/96, 49). Nevertheless, the U.S. General Accounting Office stated in the report, *Nuclear Waste: Uncertainties about Opening Waste Isolation Pilot Plan,* that prospects for opening WIPP by 1998, in accordance with DOE plans, are uncertain (GAO/RCED-96-146)(NN 10/96, 39).

Regulatory Issues and Related Matters: Radiation Health Risks and the Linear, No-Threshold (LNT) Hypothesis.

Current health and safety standards for ionizing radiation are based on the "linear, no threshold (LNT) hypothesis" in which health effects at very low doses are estimated by linear extrapolation to zero from health effects at high doses. According to the LNT hypothesis, any exposure to an individual carries with it some risk, in proportion to the dose received, and low individual exposures to large populations are likely to produce the same numbers of detrimental effects as large individual exposures to small populations. In recent years, the LNT hypothesis and its use in establishing exposure standards has come under criticism as lacking scientific foundation. The competing theory is that there is a threshold of individual exposure below which it is impossible to determine whether there is any adverse health effect at all. Some argue that at low doses there may actually be a beneficial effect, or radiation hormesis. The different approaches have potential implications for radiological health and safety standards and practices.

The Health Physics Society adopted a position statement in January 1996 that the risks of health effects of a lifetime occupational and environmental exposure above background with a value "below 10 rem, are either too small to be observed or are non-existent." The Society's position statement regarding the linear, no-threshold model stated that, "There is, however, substantial scientific evidence that this model is an oversimplification of the dose-response relationship and results in an overestimation of health risks in the low dose range." The position statement recommends that quantitative "...estimates of risk should be limited to individuals receiving a dose of 5 rem in one year or a lifetime dose of 10 rem in addition to natural background." (HPS 1996). With respect to radiation protection, the HPS position statement concludes: "Limiting the use of quantitative risk assessment, as described above, has the following implications for radiation protection:

(a) The possibility that health effects might occur at small doses should not be entirely discounted. Consequently, risk assessment at low doses should focus on establishing a range of health outcomes in the dose range of interest including the possibility of zero health effects.

b) Collective dose (the sum of individual doses in an exposed population expressed as person-rem) remains a useful index for quantifying dose in large populations and in comparing the magnitude of exposures from different radiation sources. However, for a population in which all individuals receive lifetime doses of less than 10 rem above background, collective dose is a highly speculative and uncertain measure of risk and should not be quantified for the purposes of estimating population health risks"(HPS 1996).

Carbon Emissions and Energy Use

National and international policy continues to evolve in an attempt to address the concerns surrounding the increasing emission of greenhouse gases (carbon dioxide, methane, nitrous oxide, and others) and their potential effect on the Earth's temperature and climate (Appendix B). In 1996, the annual Conference of the Parties (developed country signatories of the 1992 Framework Convention on Climate Change) issued a "Ministerial Declaration" instructing government representatives to negotiate a "legally-binding protocol" that specifies "policies and measures," including "quantified objectives for emission limitations and significant overall reductions within specified timeframes, such as 2005, 2010, 2020, with respect to their anthropogenic emissions." As of mid-year 1997 the United States and other countries had not agreed on binding protocols. The U.S. has emphasized the importance of "joint implementation between developed and developing countries," emissions trading, and "flexible approaches"—positions that are not popular with several developing and other developed countries. Concern and controversy over the establishment of fixed stabilization commitments, i.e., a cap on carbon emissions, is focused on the economic costs of shifting away from carbon-based fuels, different levels of optimism over the opportunities for technological substitution, whether policy should be pursued nationally or internationally, and when and if all nations contributing to carbon emissions pledge to strive towards stabilization goals (EGG 1996, 8-10).

Although the United States is the world's largest single emitter of carbon dioxide, contributing 23% of the energy-related carbon emissions worldwide, the growth in emissions worldwide has come from rapid growth in developing nations. U.S. anthropogenic carbon dioxide emissions in 1996, generated primarily by the combustion of coal, natural gas and petroleum, were estimated at 5,484.9 million metric tons, a 3.5% increase over 1995 and an 8.9% increase over 1990 emissions (Table 5). Growth in U.S. carbon emissions from 1995-1996 reflects a relatively robust economic growth of 2.4 %, a 3.2% increase in energy consumption, and an almost 5% increase in coal consumption by the energy sector as it switched from higher-priced natural gas to coal for their fuel requirements. These factors more than offset the benefits of increased hydropower associated with above-normal precipitation in the Northwest in 1996 (EGG 1996, 13).

Table 5: U.S. anthropogenic emissions from energy and industry, 1990, 1995 and 1996
(Million metric tons of carbon or carbon equivalent)

Emissions-mmtc[1]	Carbon Dioxide	Methane	Nitrous Oxide
1996 emissions	1,479	167	86
Change from 1995 to 1996	51 (3.6%)	- 5 (-2.9%)	-2 (2.3%)
Change from 1990 to 1996	123 (9.1%)	- 6 (-3.5%)	4 (4.9%)
Global warming potential (GWP)	1	21	310

Emissions of Greenhouse Gases in the United States—1997, DOE/EIA-0573(97) U.S. Department of Energy, Washington, DC (Oct. 1998, T. ES2)
[1] mmtc = million metric tons of carbon equivalent based on global warming potential

The DOE/EIA projects that most of the future growth in energy consumption is expected to be in the transportation sector and in the use of electricity. The following emissions by sector are defined as the sum of emissions resulting from the direct burning of fuels in addition to the emissions associated with the production of electric power used by the sector (Table 6) .

Table 6. U.S. carbon dioxide emissions from energy consumption by end-use sector
(Million metric tons of carbon)

Sector	1990	1995	1996
Industrial Sector	454.1	465.0	478.3
Transportation Sector	432.1	458.5	470.7
Commercial Sector	206.8	217.9	226.0
Residential Sector	253.1	270.3	285.6
Total Energy Carbon	**1,346.1**	**1,411.7**	**1,460.6**
Electric Utility	476.9	495.3	513.3

Emissions of Greenhouse Gases in the United States—1997, DOE/EIA-0573(97), U.S. Department of Energy, Washington, DC (Oct. 1998, 134).
Note: Emission from electric utility are distributed across end-use sectors.

The industrial sector is responsible for one-half of all U.S. carbon dioxide emissions over the last decade. Gross primary energy consumption exceeded 32 quads in 1996, dominated by the need for heat and power, with a large share of industrial energy involving consumption of raw materials for chemical feedstock. Natural gas and electricity (including losses) each account for approximately one-third of the energy consumed by the industrial sector. Emissions of carbon dioxide by the sector were 478.3 mmtc in 1996, 2.9% more than in 1995 and 24.2 mmtc more than in 1990, an increase of more than 5%. Industrial processes produce 17 to 19 mmtc emissions per year. More than 50% of the carbon emissions from industrial processes are from the manufacturing of cement. In 1996, approximately 79 million metric tons of cement were produced, releasing approximately 19 mmtc (EGG 1996, 13,14,17; EGG 1997, 134).

Gross fuel use by the transportation sector exceeded 24 quads in 1996, consuming more than 7.8 million barrels of gasoline per day. This sector consumed two-thirds of the oil consumed in the U.S., emitting one-third of U.S. carbon emissions. Emissions from motor gasoline, distillate, residual, and jet fuels totaled approximately 470.7 mmtc in 1996. This sector has contributed approximately 34% (38.6 mmtc) of the national increase in emissions from the end-use sectors since 1990 (EEG 1996, 15; EEG 1997, 134).

Gross energy consumption by the residential and commercial sectors combined was 33 quads in 1996, attributed to the use of natural gas and electricity primarily. Residential emissions associated with primarily space heating and cooling increased by more that 6% in 1996 due increased consumption of distillate fuels and natural gas in response to severe weather. Residential emissions have accounted for 32.5 million metric tons (approximately 28%) of the increased carbon dioxide emissions by end-use sectors since 1990. Approximately 14 quads were consumed by the commercial sector in 1996, with electricity accounting for more than one-half of that amount. Commercial sector carbon emissions increased to 226 mmtc (3.5%) in 1996. From 1990 to 1996, this sector was responsible for a 19.2 million-ton (16.7%) increase in U.S. carbon dioxide emissions (EEG 1996, 15,16; EGG 1997, 134).

U.S. anthropogenic emissions of methane reached 30.9 million metric tons in 1996, well below the 31.6 million metric tons emitted in 1990. (The DOE/EIA's estimates of methane emissions carry a 3% to 5% uncertainty since emissions of methane are usually accidental or incidental to biological processes that are not metered in any way.) The three primary sources of methane emissions in the U.S. are energy production and consumption, waste management, and agriculture. Energy production produced 11.6 million metric tons of methane emissions in 1996, compared to 12.1 million metric tons in 1990. Emissions in 1996 were however 430,000 metric tons higher than in 1995 resulting from a large rise in gas vented at oil wells. The total amount of natural gas that was vented or flared in the U.S. increased from 150 billion cubic feet in 1990 to 263 billion cubic feet in 1996. This flared portion created 3.4 mmtc emissions in 1996. Methane emissions from coal mines were more than 15% less than in 1990 due to increased methane recovery, production consolidation, and aggressive pre-mining degasification from the nation's gassiest mines.

This reduction is considered extraordinary since coal production reached record levels in 1996, driven by a 6% increase in coal consumption for electricity generation. Methane emissions from stationary sources, primarily from residential wood consumption (90%), reached 594,000 metric tons in 1996, 19,000 metric tons higher than in 1990. Methane emissions from mobile sources reached 249,000 metric tons in 1996, more than 24,000 metric tons below 1990 levels. A 58% decrease in emissions from passenger cars was achieved from 1980 to 1994, however annual reductions due to fleet turnover (with more efficient catalytic converters) are decreasing as the fleet of light-duty trucks is rapidly growing and the number of vehicle miles traveled is increasing (4.5% increase since 1994; 2% increase in 1996). Estimated methane emissions from landfills was 10.3 million metric tons, 6.2% less than in 1990. This reduction is attributed to more waste being recycled or incinerated rather than being sent to landfills, as well as increased methane recovery. Commercial wastewater treatment is another source of methane emissions in the U.S., estimated at 0.16 million metric tons in 1996 (6.4% increase over 1990 levels). Agricultural sources of methane emissions are significant and represent 28% of all U.S. anthropogenic methane emissions. Approximately 94% of the 9 million metric tons of methane released in 1996 are traced to animal husbandry. Other agricultural sources include rice cultivation (400,000 metric tons) and burning crop residues (139,000 metric tons). Industrial processes such as chemical production, and iron and steel production also contribute to atmospheric methane, and in 1996 this contribution was 74,000 metric tons and 59,000 metric tons respectively. Methane's global warming potential (GWP) is estimated to be 21 times greater than carbon dioxide (EGG 1996, 23-30).

Principal sources of anthropogenic nitrous oxide emissions in the U.S. are energy use, agriculture and industrial. In 1996, these emissions totaled 446,000 metric tons. Although the amount of nitrous oxide released to the atmosphere is small relative to carbon dioxide and methane, a 100-year global warming potential (GWP) of 310 makes nitrous oxide an important contributor to atmospheric warming. Energy use is the largest source of anthropogenic nitrous oxide emissions contributing 189,000 metric tons (42.4%) to the total, and includes mobile-source combustion from cars, buses, motorcycles, and trucks, and stationary-source combustion from residential, industrial, and electric utility energy use. Nitrous oxide emissions from energy use have increased only 0.4% since 1990, whereas industrial sources have increased 14.1% and agricultural sources decreased 11%. Approximately 75% of the 1996 emissions were produced by coal-fired combustion systems, and approximately 67% from electric utilities. Agricultural practices such as fertilizer use and crop residue burning contributed approximately 33% of U.S. nitrous oxide emissions in 1996 whereas on a global scale, these practices contributed approximately 70% of anthropogenic nitrous oxide emissions. Industrial processes such as adipic acid and nitric acid production increased 14.1% since 1990 contributing an estimated 111,000 metric tons of nitrous oxide to the atmosphere in 1996.

Emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) increased 69.5% since 1990, contributing 42.4 mmtc to the atmosphere. Introduced commercially in the 1990s as replacements for chlorofluorocarbons, emissions of HFCs, particularly HFC-134a used in motor vehicle air conditioners, have grown rapidly. Pursuant to the Montreal Protocol, the use of chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) which are greenhouse gases outside the scope of the Framework Convention (see Appendix B), are being phased out and replaced with nonchlorinated compounds such as HFCs and PFCs. Although all of the above compounds are potent greenhouse gases with large GWPs, because HFCs and PFCs only contain hydrogen, fluorine and carbon, they do not destroy ozone, which makes them a desirable replacement for CFCs. New varieties of HFCs are being developed as CFCs are being phased out, making accurate quantities of emissions difficult. Estimates of these compounds and their GWPs are shown in Table 7.

In his testimony before the Energy and Natural Resources Committee of the U.S. Senate September 17, 1996, the Under Secretary for Global Affairs, Timothy Wirth, presented the Clinton Administration's efforts to address the "far-reaching challenges" of global climate change. The Administration supported the findings of the IPCC:

- "The chemical composition of the atmosphere is being altered by anthropogenic emissions of greenhouse gases."
- "The continued buildup of these gases will enhance the natural greenhouse effect and cause the global climate to change."
- "Based on these facts and additional underlying science, the second assessment reported that, the balance of evidence suggests that there is a discernible human influence on global climate."

Under Secretary Wirth noted that it is the objective of the U.S. to stand behind the findings of the IPCC; to take action to reduce carbon emissions; to shift negotiations towards strategies that are economically sensible, verifiable and binding; to ensure that national and international flexibility are preserved; and to ensure that all nations, developed and developing are involved in the negotiations in determining the most cost-effective and innovative mechanisms are used.

U.S. carbon emissions from energy use are projected by the DOE/EIA (reference case) to reach 1,975 million metric tons by the year 2020, an average increase of 1.3% per year, and 47% higher than 1990 levels. Increased emissions are expected to be the result of projected increases in energy demand (avg. 1.1% increase per year), a decreasing role for nuclear power, and the slow development of renewable energy as well as anticipated decreases in the price of natural gas and petroleum. (AEO 1999, 3-7).

In comparison, world energy use is projected to increase 2.3% annually, or at total incremental increase of 75% between 1995-2020 (reference case). Most of the demand will occur in developing Asia, Africa, Central and South America, and the Middle East. Given these projections, world carbon emissions will reach 8.3 billion metric tons per year by 2020, exceeding 1990 levels by 81% (IEO 1998, 7-19).

Table 7. Estimated 1996 U.S. hydrofluorocarbon and perfluorocarbonemissions.

Compound	Emissions (metric tons)	Carbon Equivalent (mmtc)[1]	% Change since 1990	100-Year Global Warming Potential (CO_2=1)	Emission Sources
HFCs[2]		26.4	98.5		
HFC-23	3,000-5,000			11,700	By-product of HCFC-22 production; semiconductor mfg.
HFC-134a	11,000		2200.0	1,300	Auto air conditioners; refrigerant; non-flammable. liquefied gas propellant.
HFC-152a	900[3]		300.0	140	Blowing agent; refrigerant blends; fluoropolymer mfg.
PFCs[4]		6.8	31.6	6,900-9,200	Byproduct of aluminum production
SF_6	1,000	9.2	40.4	23,900	Electrical insulator

1. million metric tons carbon
2. Includes other "new" HFCs such as HFC-32 (GWP 650), HFC-125 (GWP of 2,800), HFC-143a (GWP 3,800), HFC-227ea (GWP 2,900), HFC-236a (GWP 6,300).
3. Data is for 1995. 1500 metric tons were emitted in 1994 (a 500% change since 1990).
4. PFCs although not regulated, these compounds are drawing the attention of the Climate Change Action Plan (CCAP) not only because of their high GWPs but also because of their long atmospheric lifetimes (up to 50,00 years).

Emissions of Greenhouse Gases in the United States 1996 , DOE/EIA-0573(96), Department of Energy, Washington, DC (Oct. 1997, 45-53).

Appendix A

Data and Conventions Used in Construction of Energy Flow Charts

Data for the flow charts were provided by tables in the Department of Energy's *Annual Energy Review—1997,* the *Renewable Energy Annual—1997,* and the *Monthly Energy Review (12/97).*

The residential and commercial sector consists of housing units, nonmanufacturing business establishments, health and educational institutions, and government office buildings. The industrial sector is made up of construction, manufacturing, agriculture, and mining establishments. The transportation sector combines private and public passenger and freight transportation, including military operations.

Utility electricity generation includes power sold by both privately and publicly owned companies. The non-fuel category of end use consists of fuels that are not burned to produce heat, e.g., asphalt, coal oil, petrochemical feedstocks such as ethane, liquid petroleum gases, lubricants, petroleum coke, waxes, carbon black, and crude tar. Coking coal traditionally is not included.

The conversion and plant losses associated with utility electrical power generation are a matter of record. Transmission losses are the difference between total transmitted electricity and receipts by the principal end-use sectors. They are estimated to be 9% of the gross generation of electricity by utilities. In other sectors, such as residential/commercial, industrial and transportation, the division between "useful" and "rejected" energy is arbitrary and depends on assumed efficiencies of conversion processes. In the residential and commercial end-use sectors, a 75% efficiency is assumed, which is a weighted average between space heating at approximately 60% and electrical motors and other electrical uses at about 90%. Eighty percent efficiency is assumed in the industrial end-use sector and a generous 20% in transportation. This is below the 25% efficiency we have used in past years. The latter percent corresponds to the approximate efficiency of the internal combustion engine as measured on the bench by "brake thermal efficiency" tests.

We have persisted in expressing these approximate efficiencies in our flow charts over the years, although we are fully aware of the changes in all end-use sectors that have modified actual efficiencies to some degree over the same time period. Unfortunately we lack quantitative data to improve our estimates. We feel, however, that despite improved mileage for highway vehicles, it is unlikely that transportation efficiencies in reality have reached 20% and certainly not the 25% associated with bench tests. In other end-use sectors, not only have some efficiencies changed but also the slate of fuels used by the various end-use sectors has changed, which influences the average efficiency for the sector. For example, electrical usage has steadily risen in the residential and commercial sectors because of increased use of air conditioners; natural gas has a bigger share of the heating market than in the past. We are uncertain of the net result of these changes. Another uncertainty has to do with the influence of cogeneration and self-generation of electrical power on overall industrial efficiencies. Clearly the magnitude of the effect relates to the waste heat associated with nonutility electric generation that is used in other industrial processes. Rather than abandon the approach because of uncertainties, we continue to estimate "rejected" and "useful" energy in order to point out which of the various energy sectors are associated with the largest absolute losses, such as electrical power production and transportation, and thus to direct attention to the most fertile ground for technological improvements.

There are some minor differences between the total energy consumption shown in the energy flow chart (Fig 1) and the DOE/EIA totals given in Table 2. The industrial consumption total in Table 2 agrees with DOE's *net* industrial total. Both totals include natural gas lease and plant fuels and non-fuel ("non-energy") use, which are shown separately in the flow chart.

Conversion Factors

The energy content of fuels varies depending on source, fuel type, and year. Some conversion factors, useful for estimation, are given below.

Fuel	Energy content (Btu)
Short ton of coal	21,400,000
Barrel (42 gallons) of crude oil	5,800,000
Cubic foot of natural gas	1,027
Kilowatt hour of electricity	3,412

More detailed conversion factors can be found in the appendices of DOE/EIA's *Annual Energy Review* or *Monthly Energy Review.*

Appendix B

Global Climate Change Policy Developments

1950s	Rising CO_2 concentrations first detected.
1970s	Observations of atmospheric concentrations of methane, nitrous oxide, other gases began.
Mid-1980s	Series of international workshops concerning rising atmospheric concentration of greenhouse gases moves topic onto the agenda of the UN and the World Meteorological Office.
1988	Intergovernmental Panel on Climate Change (IPCC) formed under the auspices of the UN to accumulate climate change data and advise policy makers.
1990	UN established the Intergovernmental Negotiating Committee (INL) for a Framework Convention on Climate Change.
1991	INL host sessions resulting in the signing of the Framework Convention on Climate Change by 160 nations (Rio de Janeiro, 5/4/1992). The goal of which was to "achieve stabilization of greenhouse gas concentrations to prevent dangerous anthropogenic interference with the climate system. The Framework Convention was based on voluntary commitments. It covered greenhouse gases not covered by the Montreal Protocol, i.e., CFCs and HCFCs.
1992	Bush Administration prepare draft National Action Plan.
1993	President Clinton committed the U.S. to stabilizing its emissions of greenhouse gases at 1990 levels by year 2000. The methods proposed to achieve this were published in the President's "Climate Change Action Plan" (October 1993) (CCAP).
1994	"Technical Supplement" to CCAP published defines assumptions underlying the plan.
1995	Annual meeting of the Conference of the Parties met in Berlin to discuss implementation of the Framework Convention and review countries' voluntary commitments to limit their emissions. Berlin Mandate was signed: Focus was on what steps to take after the year 2000. Developing countries encouraged to implement their commitments under the Framework Convention. Annex I (developed countries) would move ahead with additional measures.
1996	Second Conference of the Parties issued a "Ministerial Declaration" that governments would instruct their representatives to accelerate negotiations on a legally binding protocol ... to be completed in time for the Third Conference of the Parties, that should encompass the policies and measures of the Berlin Mandate and legally-binding objectives for emission limitations within time frames such as 2005, 2010, 2020.

Ref. *Emissions of Greenhouse Gases in the United States 1996*, DOE/EIA-0573 (96), U.S. Department of Energy, Washington, DC (Oct. 1997) pp. 8–11.

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